Appendix B—Survey of DG Policy

Survey Introduction

EESC conducted a survey of regulatory bodies in Europe, Australia, Japan, and the United States to determine the methodology used by each to promote distributed generation (DG). The survey includes regulatory agencies, in the countries listed below.

- Australia
- Canada
- Denmark
- European Union
- Japan
- New Zealand
- The Netherlands
- United Kingdom
- United States
    - California
    - New York
    - Texas

The results of the survey are discussed in the following sections.

B.1 Australia

Table B-1
Survey Summary – Australia

Distributed generation accounts for nearly nine percent of the total generating capacity in Australia. The following regulatory agencies were surveyed:

- Australian Essential Services Commission (ESC)
- Australian Energy Regulator (AER)

AER's role is expanding as it is set to replace the various jurisdictional regulators and become a 'one stop shop' regulator for the energy sector on a national basis.

Issue	Status
Siting and Permitting	Classified DG into four categories (<2 kW, 2kW – 1MW, 1MW – 5MW, >5MW). Licensing requirements differ by jurisdiction. A review to streamline requirements is underway.
System Interfaces	National Energy Rules establish access arrangements for DG to the network. Less than 5 MW, the DG is exempt from registering as a generator. Between 5 MW and 30 MW, the unit is registered as a non-scheduled generator. Above 30 MW, generation units are registered as scheduled units. In addition, for any of the registered units, additional classification related to market vs. non-market registration is required. If the output from the DG unit will be sold to the LDC or a customer, the unit is a non-market unit. If the output will be sold into the market, the unit is a market generator.
Interconnection Standards	Established working group to address barriers to DG, such as interconnection contract negotiations between utilities and customers.
LDC Ownership of DG	
Stranded Costs	Connection costs are required to be fair and equitable, but the methodology differs by jurisdiction. Potential for stranded costs. This issue is, one of many, being addressed by working groups.
System Investments	Addressing pricing issues, such as how to quantify the benefits of DG on the distribution system such as delaying or avoiding system upgrades. Utilities are required to pay for network support services and avoided transmission charges.
Standby Charges	Addressing pricing issues, such as standby charges that incorporate the benefits of DG on the system and the utility cost for maintaining excess capacity when the DG system is not in use.
Incentives for DG	Incentives include: ■ Photovoltaic Rebate Program (PVRP) – provides rebates for all PV systems over 450 watts installed by residential customers, community organization or school providing educational promotion of PV, and by display home builders and housing estate developers promoting PV. Rebates are capped at 1 kW. ■ Mandatory Renewable Energy Target – requires energy retailers and other large electricity buyers to source an additional 2 percent of their electricity from renewable or specified waste-product energy sources by 2010. ■ Green Power – the Renewable Energy Development Initiative (REDI) provides up to $100 million over seven years in the form of matching grants to support development of new renewable energy technologies. Matching grants start at $50,000 up to $5 million for eligible projects.
Other Issues	

Distributed generation accounts for nearly nine percent of the total generating capacity in Australia. Some of the key drivers of the adoption of DG in Australia include rising energy prices, large potential for solar applications, growing summer peak demand, environmental concerns, energy security concerns, and large potential for industrial cogeneration applications. Regulatory issues related to DG are handled primarily by the following two agencies:

- Australian Essential Services Commission (ESC) - The Australian Essential Services Commission has been Victoria's independent economic regulator of the electricity, gas, ports, grain handling and rail freight industries since January 1, 2002. Beginning January 1, 2004, the Commission became responsible for the regulation of Victoria's water and sewage services.

- Australian Energy Regulator (AER) - On July 1, 2005, the AER assumed the Australian Competition and Consumer Commission's (ACCC) responsibilities for the regulation of wholesale transmission revenues in the National Electricity Market. The AER enforces the National Electricity Law and National Electricity Rules. AER's role will be expanding over the next two years as it is set to replace the various jurisdictional regulators and become a 'one stop shop' regulator for the energy sector on a national basis. A single and independent national regulator will reduce regulatory costs and uncertainty to business, and allow both the gas and electricity markets to develop, as much as possible, within a consistent regulatory framework.

Current DG Approach, Incentives and Tariff Treatment

Distributed generation has typically been used in large scale industrial processes with both heat and electricity requirements, or as back-up emergency generation source for hospitals and city office buildings. Since 1999 there has been a rise in interest in renewable energy resulting in an expansion of grid-connected systems. The change is attributable in part to a range of State and Commonwealth programs such as the Federal Government's Photovoltaic Rebate Program, the Mandatory Renewable Energy Target, and the promotion of Green Power to electricity customers.

<u>Photovoltaic Rebate Program</u>[1]: The Photovoltaic Rebate Program (PVRP) was introduced to encourage the long-term use of photovoltaic technology to generate electricity from sunlight and to increase the use of renewable energy in Australia. Key objectives are to:

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[1] PVRP Program: http://www.greenhouse.gov.au/renewable/pv/index.html

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- Reduce greenhouse emissions
- Assist in the development of the Australian PV industry
- Increase public awareness of renewable energy

The program provides rebates to homeowners who, community organizations, schools, and home builders/developers for PV installation and education. Different conditions, rebate levels and upper limits apply.

In general, applicants may only apply for one PVRP rebate for a given property. Power ratings used in assessing eligibility and PVRP funding are based on the nominal peak watt rating of approved modules under standard test conditions. The minimum amount of new PV to be installed is 450-watt peak output. There is no maximum amount of capacity, although total rebate amounts are capped. Applicants who fully satisfy the conditions for residential PV systems will receive a rebate based on the peak output of the new PV component of the system. New PV systems will receive rebates capped at 1.0 kW.

Mandatory Renewable Energy Target[2]: As part of a broader package of national greenhouse response measures, the Australian government has set targets for the inclusion of renewable energy in electricity generation by the year 2010. Electricity retailers and other large electricity buyers will be legally required to purchase or produce an additional 2 percent of their electricity from renewable or specified waste-product energy sources by 2010 (including through direct investment in alternative renewable energy sources, such as solar water heaters). This will accelerate the acceptance of renewable energy in grid-based power applications, and provide an ongoing base for commercially competitive renewable energy.

Specific objectives of the renewable energy target are:

- To accelerate renewable energy in grid-based applications (to reduce greenhouse gas emissions)
- Provide an ongoing base for the development of commercially competitive renewable energy
- To contribute to the development of internationally competitive industries that could participate effectively in the growing Asian energy market.

It is estimated that the measure will lead to average price increases for electricity by 2010 of around 1.3 – 2.5 percent or \$100-\$250 million in 2010 (based on generation costs). It is expected that the measure will result in greenhouse gas savings of between 4 – 5.5 metric tons (MT) of CO2 equivalent depending on demand growth and the impact of the measure on the fossil fuel generation mix.

[2] *Securing Australia's Energy Future*. Commonwealth of Australia, 2004.

Green Power[3]: The Australian Government recently adopted the Renewable Energy Development Initiative (REDI) which is a competitive grant program supporting renewable energy innovation and its early-stage commercialization. The program provides matching grants from $50,000 up to a limit of $5 million for eligible renewable energy technology projects extending up to three years. The program will provide up to $100 million over seven years in the form of matching grants to support the development of new renewable energy technology products, processes or services that have strong early-stage commercialization and emissions reduction potential.

Eligible applications will be assessed against the following criteria:

- Management capability of the customer;
- Commercial potential of the project;
- Technical strength of the project and the technical capability and resources available to the customer;
- Extent to which the project is likely to provide national benefits;
- The need for funding; and
- Potential for greenhouse gas abatement.

The Ministerial Council on Energy recently identified the specific challenges to distributed generation in Australia (2006)[4]:

- Emerging technology issues;
- Resource and business opportunity identification, project approvals, access rights to resources, consumer confidence;
- Network pricing and price regulation;
- Network connection arrangements; and
- Network management and development.

The problem for DG becomes further evident when it is argued that a generator should only receive the market value of the generation, i.e., the retail price minus distribution and transmission costs. Additional pricing issues include avoided transmission charges, distribution network costs, and standby charges.

Avoided Transmission Charges: Distributed energy generators that are connected to the distribution network, bypass the transmission system (>66kV to 550kV) and therefore

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[3] REDI Program:
http://www.ausindustry.gov.au/library/REDIFactsheetCADec06final20061220031317.pdf

[4] Renewable & Distributed Generation Working Group, *Impediments to the Uptake of Renewable and Distributed Energy*. Ministerial Council on Energy Standing Commission of Officials, 2006.

avoid charges related to transmission use. Under the National Electricity Rules, distributors are required to pay avoided transmission use-of system (TUOS) charges to a distributed energy generator. Difficulties have arisen due to cost allocation not being cost reflective or where the TUOS payment has no regulatory enforcement.

Distribution Network Costs: Distributed generation may allow distribution network businesses to avoid or defer an augmentation of the electricity network. This deferral in turn reduces the costs for the network owner and its users. Calculation and adjustment of distribution use of system (DUOS) charges to reflect benefit has been mixed.

Standby Charges: Standby supply charges are often paid by distributed generators to distribution companies. The distribution company argues that spare capacity needs to be retained in the system to meet generator loads when the DG unit is not available for use. Standby, however, can fail to acknowledge that generators provide an additional source of electricity supply and therefore can perform a standby function for when the network is constrained.

Regulatory and Market Issues

There has been a significant transformation of the electricity supply industry in the last 15 years moving from publicly owned State based networks to a privatized, interconnected system. The National Electricity Market (NEM) has operated since 1998 as a wholesale market for the supply of electricity to retailers and end users in Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia. The NEM is based on five interconnected regions that largely follow State boundaries with Tasmania set to join as the sixth region. The NEM is managed by the National Electricity Market Management Company Ltd. (NEMMCO).

The legal framework for the National Electricity Market is provided by the National Electricity Law[5]. The National Electricity Law together with the National Electricity Regulations provide for the National Electricity Rules which establishes the detailed operation of the NEM. The National Electricity Rules provide the framework for the operation of the wholesale electricity market, establishing access procedures for both transmission and distribution networks.

The National Electricity Rules deal with a range of issues pertinent to the planning, installation and operation of distributed generation[6], including:

- The physical operation of DG within a distribution network;
- Access arrangements for DG to a network;

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5 Australia National Electricity Rules: http://www.aemc.gov.au/pdfs/rules/rulesv12.pdf

6 *Guide for the Connection of Embedded Generation in the National Electricity Market.* Australian Business Council for Sustainable Energy, September 2003.

- Pricing principles for distribution networks and how these affect DG;
- Registration; and
- Settlements.

The National Electricity Rules prescribe requirements for connection of generation and include the requirement to establish a connection agreement with the distribution network provider on a series of charges. The complexity in negotiating network connection and network pricing, which recognizes inherent benefits of decentralized power, has been widely seen as an impediment to the grid connection of distributed generation.

To address impediments and jurisdictional inconsistencies relating to distributed generation the Ministerial Council on Energy established the Renewable and Distributed Generation Working Group in 2004. The group has recently drafted the *Code of Practice for Embedded Generation*[7].

This Code of Practice aims to deliver the following advantages:

- The provision, where appropriate, of a consistent and predictable approach to the treatment of an ***EG unit*** in the national Electricity Market;
- Facilitating the sharing of best practices in the connection of embedded generation across Australia;
- The provision of information and guidance, at a national level, on connection issues and obligations; and
- Assistance in the removal of (unnecessary) barriers to the connection of an ***EG unit*** in Australia.

[7] PB Associates, *A National Code of Practice for Embedded Generation*. The Utility Regulatory Forum, February 2006.

B.2 Canada

Table B-2
Survey Summary – Canada

DG accounts for roughly 12 percent of all installed generating capacity in the country. Energy policy in Canada is under Provincial jurisdiction; however, several national organizations are actively participating in the energy industry.

- Canadian Electricity Association (CEA) –an industry consortium addressing infrastructure, energy efficiency, technology, regulation, environment and security issues.
- National Energy Board - an independent federal agency that regulates several aspects of Canada's energy industry.
- Natural Resources Canada (NRCan) – a Canadian Government department to develop policies and programs that enhance the contribution of the natural resources sector (including energy).

Issue	Status
Siting and Permitting	Siting and permitting is handled at the provincial level, and these issues are being addressed on an individual basis.
System Interfaces	Net metering is at various stages of development across Canada; ranging from British Columbia and Ontario with developed net-metering programs; to those provinces in the preliminary stages of DG policy consideration. In addition, the Government of Canada's Budget 2003 included funding toward researching the integration of large blocks of intermittent power and DG into the grid.
Interconnection Standards	The Government of Canada's Budget 2003 established funding to remove institutional barriers to grid interconnection of DG by 2010. Interconnection standards vary by province, for example Ontario published the Distribution Systems Code, *Appendix F: Process and Technical Requirements for Connecting Embedded Generation Facilities*.
LDC Ownership of DG	
Stranded Costs	The quantification of stranded costs is handled by the individual provinces.
System Investments	This issue is primarily a provincial issue and is being addressed by several of the provinces.
Standby Charges	The standby charge development is being investigated by some of the individual provinces. This is a significant issue for Canada as DG placement increases.
Incentives for DG	National incentive programs include: ■ Climate Change Technology and Innovation Initiative (CCTII) and Decentralized Energy Production (DEP) Program – goal to remove institutional barriers that prevent DEP installation (by 2010) and for 20 percent of all new and replacement generation capacity in Canada to be met by DEP by 2025. ■ Technology Early Action Measure Program – cost sharing program for the development and demonstration of innovative technologies. ■ On-site Generation at Government Facilities – the Government of Canada is to install 15 photovoltaic systems. ■ Federation of Canadian Municipality (FCM) Green Fund – the Government of Canada is to fund the FCM to initiate green projects.
Other Issues	NRCan, jointly with CYME, is developing a software tool that can be used to evaluate the impact of DG on the transmission and distribution system. Tools such as this will assist utilities in choosing priority placement of DG where the system can receive the maximum benefit from the generation unit.

According to the WADE report[8], DG accounts for roughly 12 percent of all installed generating capacity in the country. Energy policy in Canada is primarily under Provincial jurisdiction; however, several national organizations are actively participating in the energy industry.

- Canadian Electricity Association (CEA) – The CEA is an industry consortium composed of utilities, manufacturers, consulting companies and other companies and individual members with the purpose of addressing infrastructure, energy efficiency, technology, regulation, environment and security issues.

- National Energy Board - The National Energy Board is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade.

- Natural Resources Canada (NRCan) - NRCan develops policies and programs that enhance the contribution of the natural resources sector (including energy, forests, minerals and metals) to the economy and improve the quality of life of all Canadians. NRCan is a department of the Canadian Government.

Case Study: British Columbia

BC Hydro Boston Bar Project consisted of the planned islanding of an area downstream of a distribution substation. An 8.6 MVA run-of-river hydroelectric plant is connected to one of the substation feeders with a winter peak load of 3 MW and operated by an independent power producer (IPP). The hydropower plant is equipped with islanding capability to accommodate planned islanding of primarily the interconnected feeder, and on some occasions the adjacent substation feeders as well, depending on power generation level and demand. The planned islanding practice has been functioning since 1995 and has resulted in significant reliability improvements for this BC Hydro system and financial gains for the local IPP. The project provides excellent experience basis for other utilities.

Source: BC Hydro, NRCan

Current DG Approach, Incentives and Tariff Treatment

Many provinces are experiencing an increase in the production of wind energy, which will likely be complemented by that of small hydro and combined heat and power (CHP). These technologies have the potential to provide part of the energy needs for urban, rural, as well as remote communities in Canada. With its unique structure, constraints and

[8] Kendall, Anouk. Tinkler, Mark. Godin, Marc. Dreyer, Bert. *Current Issue-Cogeneration and On-Site Power Production*. Canadian cases: analysis of decentralized energy using the WADE economic model. Tulsa: PennWell Corporation, 2007

generation mix, the Canadian power grid could greatly benefit from a greater integration of DG. Several challenges need to be addressed in order to limit the impacts and make these energy resources functional units of the future power system.

The connection of DG is being addressed by various provinces[9]. While these standards are a good first step for increasing DG integration it is likely that additional incentives are needed to encourage further DG development. Access to the grid is a challenge, especially for smaller DG systems. Because distribution systems were traditionally designed based on large generation facilities, the addition of DG facilities change the characteristics of the LDC's distribution system. There are a number of technical challenges that need to be addressed, which include:

- Distribution network planning and operation;
- Protection coordination;
- Voltage profile and voltage regulation; and
- Power quality.

Net metering is at various stages of development across Canada. British Columbia and Ontario have developed net-metering programs, while New Brunswick and Nova Scotia have recently introduced their net-metering programs. Manitoba has a long-established net-metering program, but participation levels have been low in part due to the low electricity rates in the province. Quebec is just starting a net metering for DG facilities, and Prince Edward Island is developing a net-metering program as part of the upcoming PEI Renewable Energy Act. While Alberta does not have a policy in place for net metering, Alberta Energy released *Micro-Generation: A Discussion Paper* in 2005. The remaining provinces and territories appear to be in more preliminary stages of developing their decentralized or renewable energy strategies, including consideration of net-metering policies.

[9] Distribution Systems Code Appendix F.1.1, *Connection Process for Micro-Embedded Generation Facility*.

Regulatory and Market Issues

Significant effort has been made to develop interconnection standards and codes, as well as application guides. Natural Resources Canada (NRCan), in collaboration with CYME International and utility partners, is working on tools for modeling integration of DG. It is the intention of this study to be used to educate and increase Canada's knowledge on the integration of DG and the use of these new software functionalities.

Whereas methods for determining the technical impact of DG in Canada are developing, methods for quantifying the benefits and costs associated with DG are not well defined. In certain cases a DG may negatively impact the system, whereas in different circumstances DG will greatly contribute improvements in the overall operation of the system. As the economics associated with DG likely constitute the most important barrier, it is imperative that methods for assessing the cost and benefits of DG be defined. Without properly defined methodologies, much uncertainty remains regarding the actual costs that are charged to DG owners and their benefits will not be appropriately acknowledged.

Case Study: Quebec

Sherbrooke Hydro is a small distribution company in the province of Quebec, which purchases electricity from Hydro-Quebec. The rate at which Sherbrooke Hydro buys electricity is based on a particular rate structure, whereby the cost of electricity depends on the amount of energy (MWh), the maximum power (MW) and a surcharge for any power level exceeding a predefined upper limit. This structure provides a strong incentive for peak load management. To address this issue Sherbrooke Hydro launched a program that compensates facilities for the controlled use of their back-up generators for peak demand management during peak periods, which are strongly correlated with the coldest days of the year. Sherbrooke Hydro dispatches the back-up generators of the 22 participating clients in order to limit the power required from the substation. Each of the customers is paid a rate for the energy supplied during these periods, in addition to any initial costs related to equipping their generators with grid parallel operation.

Source: IEEE Paper, *Integration of DG and Wind Energy in Canada*

Site selection of DG, as well as the selection of the technology itself, should reflect what makes the most sense in terms of costs, benefits and the needs of the local community. Wind and small hydro are technologies that could help to serve rural systems, however they are less likely to play a role in urban settings. Microgrids in Canada will most likely be based primarily on cost and reliability. Currently there are a number of applications that are of significant interest, such as to improve service on rural feeders, to reduce the use of diesel fuel in remote communities, and where sensitive loads on the grid demand a higher level of reliability (emergency and back-up power supply)[10].

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[10] **IEEE Paper,** *Integration of DG and Wind Energy in Canada*

Pilot Program Results

Electricity regulation mainly falls under provincial jurisdiction in Canada, requiring collaboration with many jurisdictions and provincial utilities. Several activities have been initiated nationally to provide on-going support to regulatory agencies that may or may not be addressing the barriers to the grid integration of DG.

In its Budget 2003, the Government of Canada announced $500 million in Science and Technology funding to help address greenhouse gas reduction and climate change. Half of the funding is allocated to the Climate Change Technology and Innovation Initiative (CCTII). The CCTII is focusing on five key technology areas:

> **Case Study: Newfoundland**
>
> Traditionally, remote communities in Canada have been supplied electricity almost exclusively by diesel units, due to the reliability and confidence in the technology. Newfoundland and Labrador Hydro has challenged the norm by incorporating a significant amount of wind into the island community of Ramea. While the utility remains ultimately responsible for supply of the load, an independent wind power producer can feed its total output of 325 kW into the system as long as the diesel unit is loaded at least 50%. The control system facilitates the smooth integration of wind and ensures interoperability with the existing remote grid. This project is the first of its kind in Canada and it is hoped it will help to increase the acceptance of this wind-diesel hybrid solution as a competitive alternative for remote system applications.
>
> **Source: IEEE Paper,** *Integration of DG and Wind Energy in Canada*

- Cleaner fossil fuels;
- Advanced end-use efficiency technology;
- Decentralized energy production (DEP)
- Biotechnology; and
- Hydrogen economy.

The primary goals under the decentralized energy production (DEP) program are the removal of institutional barriers that prevent DEP installation (by 2010), and for 20 percent of all new and replacement generation capacity in Canada to be met by DEP by 2025.[11] Decentralized energy production generally refers to environmentally preferred on-site power generating plants of less than 1 MW capacity; however, for the scope of this program, highly efficient combined heat and power plants (up to 25 MW) and wind farms are also included. In addition, the DEP program will focus on technologies specific to the unique Canadian circumstances, such as: high-velocity, low-temperature wind regimes; cold climates; wind/hydro dispatch and storage opportunities; long-transmission distances; and applications for remote, northern communities.

The DEP program will help deliver on the desired outcomes in the short, medium and long term as shown in Table B-2a.

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[11] Dignard-Bailey Ph.D., Lisa. *Canadian Program on Decentralized Energy Production.*

Table B-2a Natural Resources Canada's Anticipated Outcomes from Targeted Governmental R&D Support		
Short Term ~ 2008	**Medium Term ~ 2015**	**Long Term ~ 2025**
1 Codes & Standards **2** Interconnection guidelines and regulations **3** Resource forecasting **4** Proof of concepts **5** Grid integration modeling **6** Systems with non-traditional fuels **7** National/International innovation networks	**1** Industry adoption of new concepts **2** New national codes and standards **3** Acceptance of DEP in provincial planning and policy **4** Initial deployment of technology for industry partners	**1** Provincial and utility recognition that DEP is legitimate concept **2** Provincial strategies that lead to 35,000 MW of new renewable energy **3** Institutional approaches enable customers to use DGR and DEP technology

Source: Natural Resources Canada (NRCan)

Therefore, by 2010, the program aims to modify current codes and standards and interconnection guidelines and regulations such that on-site production will be no more restricted than onsite demand reduction. Grid integration modeling will help guide regulatory changes. Other activities will include resource assessments for renewable resources and the deployment of systems that use non-traditional fuels (waste, bioenergy). Federal research laboratories will work with universities and utilities to establish stronger research networks that will aid in understanding how to integrate large blocks of intermittent power and distributed generation into the grid.

Additional programs directed to benefiting the DG industry include the following:

- **Technology Early Action Measure Program** – cost sharing program for the development and demonstration of innovative technologies.
- **On-site Generation at Government Facilities** – the Government of Canada is to install 15 photovoltaic systems.
- **Federation of Canadian Municipality (FCM) Green Fund** – the Government of Canada is to fund the FCM to initiate green projects.

Case Study: Alberta

FortisAlberta is an electricity distributor that operates networks in Southern Alberta and has integrated a large amount of DG into their system. One particular feeder incorporates both wind and hydro generation, a combination that will likely become more common in Canada, particularly for rural systems. The installed wind generation capacity exceeds that of the load and during times of high generation the DG may produce more than the local requirements. This results in reverse power flow across many of the voltage regulators, which has caused unpredictable operation and in some cases unfavorable voltage profiles.

This case is of interest as it combines renewable technologies and illustrates some of the technical problems that can occur when DG is interconnected to systems with long lines. The participation of the utility and its willingness to collaborate has been very useful in documenting real problems and identifying limitations of conventional tools used to assess the impact of distributed generation on power systems.

Source: IEEE Paper, *Integration of DG and Wind Energy in Canada*

B.3 Denmark

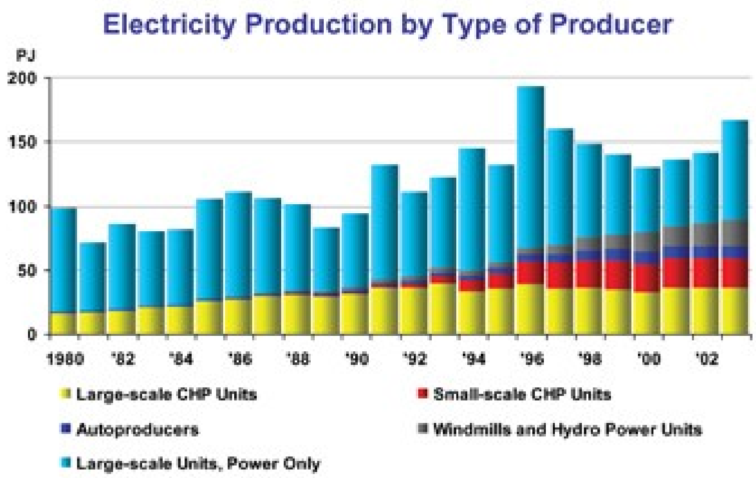
Table B-3 Survey Summary – Denmark	
DG has played a prominent role in Danish energy policy for more than two decades. Denmark has more than 6,000 decentralized energy sources, comprising nearly 600 combined heating plants (CHP) using fuels such as natural gas, waste, biogas, and biomass. In addition, since the 1970s Denmark has developed approximately 5,285 wind power plants with a total capacity of 3,138 MW. In 2005, wind power met approximately 19 percent of the total energy demand in Denmark.	

Issue	Status
Siting and Permitting	DG systems under 25 MW do not require a license to operate.
System Interfaces	As a Market participant, a DG facility is assigned a balance responsible party, which is responsible for any imbalance. However, only large DG facilities are centrally dispatched, while smaller units operate autonomous under self-dispatch. Due to issues with power quality, spinning reserves and power overflows, the transmission system operators are now allowed to curtail certain DG facilities in exchange for financial compensation.
Interconnection Standards	Danish network operators have developed connection specifications based on size of plant, with less stringent requirements for smaller plants. In addition, the Transmission Systems Operator (TRO) are allowed to temporarily cut production to certain CHP's to maintain system stability in exchange for financial compensation of the lost revenues. DG owners pay "shallow" connection charges, i.e. they pay only the costs of connecting to the grid at 10 kV. Any upstream costs are paid by the LDC, and as a result, paid by the LDC's rate payers.
LDC Ownership of DG	A large share of DG facilities are owned by LDC's in Denmark. LDC's own approximately 29% of the total CHP capacity and 14% of the total wind capacity (excluding the large off-shore wind farms) in Denmark.
Stranded Costs	The large number of DG units has lead to the decommissioning of central plants that were operational and regulated. In fact, DG capacity now exceeds the minimum system capacity needs, which is causing concern.
System Investments	Denmark has seen an increase in transmission and distribution costs recently due to the increased quantity of wind generation located in low load areas. Initially transmission and distribution improvements were avoided, however.
Standby Charges	Priority generation is exempt from the usual balancing mechanism applied to all other market participants. Deviations between forecast and actual production is paid for by the TSO. This cost is shared across all system users.
Incentives for DG	Any environmentally friendly generation of electricity is eligible for subsidy in Denmark.
Other Issues	Generally DG facilities are operated to sell to the market rather than as a stand alone facility. All CHP and renewable DG generation is "priority production" and is purchased by the LDC and resold to a TSO at a fixed price equivalent to the long-run marginal cost of conventional plants.

DG has played an important part in Danish energy policy for several decades. Denmark has a significant amount of combined heat and power production (CHP) both at large central CHP facilities in larger cities and at decentralized CHP facilities in smaller cities. A total of 1.5 million households or 60% of all households in Denmark are heated with central heat. As a consequence, today Denmark has more than 6,000 decentralized energy sources, comprising nearly 600 combined heating plants (CHP) using fuels such as natural gas, waste, biogas, and biomass[12].

According to Dansk Energi[13], since the energy crisis in the 1970s, Denmark has developed approximately 5,285 wind power plants with a total capacity of 3,138 MW. In 2005, wind power met approximately 19 percent of the total energy demand in Denmark. This share is the highest share of total production in the world.

Figure B-1



Source: Danish Energy Authority

Restructuring of the electricity markets in Denmark has to a large extent been due to the establishment of the single energy market in the EU. The object of the single market is to enhance efficiency and competitiveness while ensuring security of supply and protecting the environment.

The electricity market was restructured at the end of the 1990s. Production and trading in electricity is now subject to competition in Denmark. The electricity grid and its operation are subject to public price regulation, and all users of the system may make use of this infrastructure. Started in January, 2003, all electricity customers may purchase electricity in the open market and choose the supplier they prefer. Customers who do not wish to exercise their free choice are assured electricity supplies. Special supply

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[12] KEMA Limited, *Survey Study of Status and Penetration Levels of Distributed Generation (DG) in Europe and the US (Stage One).* Department of Trade and Industry, 2003.

[13] Danish Energy Authority, *Renewable Energy Danish Solutions*. September 2003

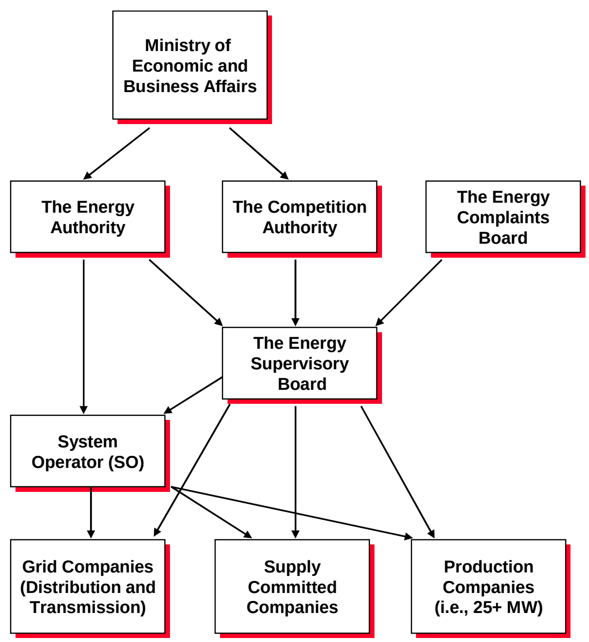
obligation companies (suppliers of last resort) offer electricity to all customers at publicly controlled prices.

Energy production based on renewable energy sources is an important component of the Danish energy supply. The utilization of renewable energy contributes to security of supply and the management of environmental pollution. Renewable energy, which includes wind power, biomass, solar power, etc. is greenhouse-neutral, i.e., it does not increase the concentration of greenhouse gases in the atmosphere. Biomass (including waste) is the single most important source of renewable energy in Denmark, and Denmark is also one of the world leaders in the use of wind energy sources.

Current DG Approach, Incentives and Tariff Treatment

The regulatory structure of the Danish electricity sector is very complex. The Energy Regulatory Authority regulates utilities in Denmark, but in actuality regulatory power is dispersed among the Energy Authority, the Energy Regulatory Authority and the System Operators (SO). To a large extent, regulatory powers are exercised through licenses and a detailed benchmark/income framework model. [14]

Figure B-2
Governance Bodies in the Danish Energy Sector



[14] Tech-wise, Sustelnet: *Review of current EU and MS Electricity Policy and Regulation – Denmark.* October, 2002.

The legislative regulation is to a large extent set out in the Electricity Supply Act[15]. The regulation comprises settlement methods, terms of grid connection, charging principles and system dispatch for a group of producers that have been given priority access to the grid. Priority production is defined as production from:

- Decentralized and industrial CHP; and
- Electricity production plants using renewable or waste resources.

Environmentally friendly generation of electricity is eligible for subsidy[16] in Denmark. Electricity generated from fossil fuels in central power stations is not eligible for subsidy. The subsidies usually depend on the fuel type, plant size, and age of the plant.

Some of the subsidies are given in the form of a premium while others are regulated in relation to market price, so that the combination of market price and supplement ensures a fixed tariff for the producer. All subsidies are passed on to the consumers as an equal Public Service Obligation (PSO) tariff on their total consumption. Public Service Obligations (PSOs) are compulsory services the state applies to companies designed to satisfy public interests. The transmission system operator and distribution system owners are subject to a number of PSOs. These PSO's fund expenditure in the following areas:

- Supply security;
- Payment of subsidies for environmentally friendly electricity; and
- Research and development of environmentally-friendly production technology.

Approximately three fourths of all PSO costs go to the subsidy for environmentally friendly electricity production. The Electricity Supply Act defines in greater detail which PSOs are involved, and states how PSO costs can be accounted for by distribution companies and passed on to the consumers.

DG facilities are required to obtain a license to produce electricity from plants with a capacity in excess of 25 MW. A license can be accompanied by a number of conditions, for example in the case of CHP plants, it could be required that the plant take on a supply commitment for district heating in a specified supply area. A license is awarded for a minimum of 20 years.

DG facilities are also required to obtain a prior permission of the Danish Energy Authority to establish new electricity production plants and major changes to existing

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[15] Energi Tilsynet: http://www.energitilsynet.dk/english/annual-reports/2002/annual-report-2002-5-regulatory-basis-for-electricity/

[16] Danish Energy Authority: http://www.ens.dk/sw12303.asp

plants. Permission requires the applicant to document that specific published conditions are met. Conditions include requirements to submit specific types of information and to comply with certain greenhouse gas emission limits. In addition, the approval from the Danish Energy Authority may specify conditions for grid connection. The executive order applies – with some exceptions – to electricity producing plants over 5 MW. The owner of a decentralized or industrial CHP plant that wants to grid-connect must make a request to the local distribution company. The distribution company must then define where the plant is to be connected. The decision is made on an objective basis. If the DG resource is a priority producer, the owner only pays to be connected to the 10 kV grid. If the distribution company on the basis of economically or technically objective reasons prefers to connect the plant to another voltage level, the distribution company defrays all extra costs such as grid extension and reinforcement. The owner of a plant who requests to be connected to a higher voltage level bears all additional costs[17].

A similar process applies when an owner wants to connect a wind turbine to the grid. The owner makes a request to the local distribution company, who in turn is committed to determine the closest possible point on the existing grid where the turbine can be connected. If the turbine(s) is to be erected in an area laid out as a wind farm, the distribution company must extend the existing grid to a point on the border of the area if the distribution company can be guaranteed that turbines with at least 1.5 MW of capacity are going to be erected in the area.

The LDC bears costs of grid extension and reinforcement (passing the cost through to ratepayers), while the owner of the turbine(s) bears all costs of connecting the turbine at the point defined by the LDC. Clearly, the LDC may be reluctant to grid-connect decentralized CHPs and wind turbines, as this implies additional costs of grid extension and reinforcement, which can especially be problematic in areas with a large wind potential.

A system of regulated third party access to the grid is in force in Denmark. LDCs are under an obligation to connect both buyers and suppliers of electricity to the grid, provided that they meet certain technical requirements. Prices and terms of grid connection are to a large extent legally regulated and must be based on transparent, objective, and non-discriminatory criteria. Furthermore, LDCs are under an obligation to notify the Energy Regulatory Authority of prices, terms, and conditions within 30 days after they have been defined, but no later than the day they enter into force. Prices, terms and conditions are made publicly available by the Energy Regulatory Authority.

Denmark has also addressed the issue of specific technical specifications for smaller plants. Traditionally, technical specifications have been targeted at larger plants, which need requirements for frequency, voltage control, etc. For that reason, the Danish network operators developed specific connection specifications based on size of plant, with less stringent requirements for smaller plants. As the share of DG increased relative

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[17] Danish Energy Authority: http://www.ens.dk/sw12303.asp

to non-DG resources, power quality, the need for spinning reserves and what to do with excess generation from DG facilities became issues that had to be dealt with. As a result, a voluntary curtailment scheme was devised. In addition, the Transmission System Owners were allowed to temporarily cut production of certain CHP's in exchange for financial compensation of the lost revenues.

> **Case Study: Denmark**
>
> Although the benefits of district heating in Denmark were recognized locally in the early part of the 20th century, it was the oil crisis of 1973, when 94% of the country's energy needs were being met by imported fuel, which provided a catalyst for growth of the sector.
>
> The Danish Government passed two key pieces of legislation to improve security of supply. The Electricity Supply Act of 1976 obliged the electricity utilities to build power stations in areas where district heating could be used. The Heat Supply Act 1979 effectively prohibited the use of electricity for heating except in rural areas that could not be served either by district heating or natural gas, and enabled local authorities (through a heat planning program) to decide whether gas or district heating should be used in specific areas and to require buildings to connect to district heating.
>
> The heat-planning program in particular has resulted in a much wider use of district heating, which has grown from 10% in 1975 to 60% of homes in 2004 being supplied by district heating. This has also reduced levels of fuel use for space heating requirements, which, in 2003, was 50% of the 1973 level. The current fuel sources for district heating are: natural gas 29%; waste 24%; coal 23%; biomass 18%; oil 7%.
>
> Around 85% of district heating companies are consumer owned with around 34% of heat sales. Municipalities own the remainder and are responsible for 66% of heat sales.
>
> **Source: DTI-Ofgem**

Regulatory and Market Issues

Several regulatory and market issues have developed in Denmark over the years. The issues with power quality, spinning reserves and excess generation as the share of DG output increased were discussed above.

Another issue is the need for additional transmission and distribution investments. Initially, DG deferred transmission investments in Denmark. However, because wind power plants are usually located in areas with low load and weak transmission system, many parts of Denmark have power flowing from the distribution system to the transmission grid[18]. This has required additional investment in the system. In addition, utilities have often found that it is necessary to invest in parallel lines, next to a customer distribution line, to access wind power facilities, further increasing the transmission and distribution investments. Because of the purchase obligation for production from priority (renewable) resources, DG has also displaced output from central power plants. As a result, some larger plants have been decommissioned, resulting in stranded assets.

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[18] KEMA Limited, *Survey Study of Status and Penetration Levels of Distributed Generation (DG) in Europe and the US (Stage One).* Department of Trade and Industry, 2003.

Pilot Program Results

Denmark's experience with CHP and wind power is a prime example of how a significant amount of DG can be incorporated into the energy portfolio of a country. However, additional fuel sources are also desirable to add diversification to the resource mix.

In Denmark, biomass currently accounts for approximately 70% of renewable-energy consumption, mostly in the form of straw, wood and waste. Consumption of biomass for energy production in Denmark more than tripled between 1980 and 2004. A further increase is expected in 2004 due to the policy agreement (the Biomass Agreement[19]) on the use of straw and chips at cogeneration plants. At the same time, the consumption of biomass continues to rise as a source of energy for the supply of heat in district-heating plants and in smaller installations for households, enterprises and institutions.

[19] Biomass agreement:
http://www.ens.dk/graphics/UK_Energy_Policy/Danish_energy_policy/Political_agreements/Aftale140693.doc

B.4 European Union

Table B-4
Survey Summary – European Union

The European Union (EU) is composed of 27 democratic member states of Europe and was established in 1992 by the Maastricht Treaty. The Union has a single market, a single currency (the euro which has been adopted by 13 member states and is managed by the European Central Bank), and common defense, agricultural, trade and fisheries policies.

Issue	Status
Siting and Permitting	Members are required to review and improve the process to site, permit and license DG (including renewables and CHP).
System Interfaces	EU is continuing to address market access and facilitation of DG resources. If DG resources are bid into the market, many jurisdictions exempt DG, and in particular intermittent resources, from balancing & ancillary charges
Interconnection Standards	Promoting standards for interconnection.
LDC Ownership of DG	
Stranded Costs	The general philosophy is that DG should get credit for the full costs and benefits of access to the system. Therefore, the EU is considering locational pricing such that an accurate pricing signal can be provided to DG developers.
System Investments	Addressing avoided costs and benefits of DG.
Standby Charges	
Incentives for DG	Renewable energy sources general receive preferential treatment. This is likely to continue in light of GHG targets.
Other Issues	Many of the barriers identified in the DECENT project are in general terms addressed by current legislative proposals at the EU level, such as the proposed amendments to the Electricity and Gas Directives, the proposed CHP Directive and the Renewables Directive of 2001. The DECENT project has elaborated further with more practical recommendations on how to tackle the main barriers to DG within the framework of existing and developing EU legislation. The EU is continuing to research: ▪ Removal of barriers related to access to market ▪ Congestion pricing to promote local DG ▪ Priority to generation units using renewable energy sources or CHP.

The European Union (EU) is composed of 27 democratic member states of Europe and was established in 1992 by the Maastricht Treaty. The EU is the largest political and economic entity on the European continent, including approximately 500 million people and an estimated GDP of 13.4 trillion US$. The Union has a single market, a single currency (the euro which has been adopted by 13 member states and is managed by the European Central Bank), and common defense, agricultural, trade and fisheries policies.

Current DG Approach, Incentives and Tariff Treatment

The EU recognizes that when modeling future electricity systems, a fundamental fact will be that with increased levels of distributed generation penetration, the distribution network can no longer be considered as a passive appendage to the transmission network – the entire system has to be designed and operated as an integrated unit. In addition, this increasingly complex operation must be undertaken by a system under multiple management.

The advent of increased DG penetration brings new business opportunities. The communications systems required to operate the energy market will be open systems and an effective energy "stock market" will be enabled. Such systems will require that uniform energy and information interfaces are established, probably using internet-based information networks.

EU rationale for formulating future policies which move toward decentralized generation are as follows[20].

- Meeting Kyoto Objectives: 8% CO2 reduction between 2008 and 2012 compared to 1990 level;
- Restructuring of the internal market for electricity;
- Improving energy efficiency;
- Improving security and diversity of supply;
- Developing renewable energy sources and CHP Directives; and
- Moving toward the hydrogen energy economy.

Regulatory and Market Issues

In the recently concluded DECENT[21] project, a consortium of European research institutes identified the main barriers to, and successes of, the implementation of decentralized generation projects within the EU. The following summarizes the main recommendations from the project – particularly those on grid and market access.

Development of EU Policies

Decentralized or distributed generation is expected to play an increasingly important role in the European electricity infrastructure and market, contributing to the EU Kyoto target for greenhouse gas emissions reduction, and the 22% target for the share of electricity from renewable energy sources by 2010. The application of DG is often highly location specific, and depends on diverse issues such as the possibilities of

[20] European Commission Research:
http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_dg/article_1159_en.htm

[21] Uyterlinde, M.A., van Sambeek, E.J.W., Cross, E.D., Jorb, W., Loffler, P., Morthorst, P.E., and Jorgensen, B, Holst, *Decentralized Generation: Development if EU Policy.* DECENT Project October 2002

technical implementation, resource availability, environmental aspects, social embedding of the project, regulation and market conditions. These factors vary considerably among technologies and among the EU Member States. Current liberalization of the European electricity market is changing market conditions and thus provides both barriers and opportunities for DG.

Policies Affecting Decentralized Generation

The market position of DG is particularly influenced by support policies for renewables and CHP and by the ongoing liberalization of the electricity market.

The Electricity Directive 96/92 provides a general framework for DG in the area of network access and unbundling requirements. The most significant existing EU legislation for clarifying regulatory issues relating to DG is the EU Renewables Directive of 2001, and in particular its provisions relating to grid system issues. Similar rules are also under development for CHP under the proposed Directive on the promotion of cogeneration. In addition, the revised proposal for a Directive to amend the Electricity and Gas Directives defines distributed generation as 'generation plants connected to the low-voltage distribution system' and sets forth rules on how DG should be treated. The main regulatory issues common to all of these documents are authorization and permitting, grid access and market access.

Authorization and Permitting

Authorization and permitting can cause time delays and additional transaction costs to DG projects. A variety of authorizations, licenses, consents, or permits are required, usually issued or granted by various authorities. The provisions in the Renewables Directive require EU members to review and improve their administrative procedures for planning and permitting processes in terms of speed and transparency. The main recommendations are:

- Permitting or licensing procedures should be transparent and efficient;
- Introduce fast-track authorization procedures;
- Pre-selection of potential sites for DG development in spatial plans helps to avoid conflicts between DG and other uses;
- The work of planning authorities could be facilitated by improving the access to information on resource potentials for renewables and heat demand; and
- Implement training programs to familiarize local authorities with the needs and requirements of DG.

These provisions are already partly incorporated in the Renewables Directive, and should also be part of the proposed CHP Directive and the amended proposed directive on Energy Performance of Buildings. The European Commission could also require EU countries to conduct feasibility studies for CHP (heat planning, energy planning or similar) in regional and local spatial planning procedures. This could be a more specific requirement than the current requirement to assess the national potential for CHP as stated in the proposed CHP Directive. Through its energy framework programs, the European Commission could foster international exchange programs on best practice in authorization procedures.

The case studies conducted in the DECENT project demonstrated that local support for DG projects is essential. One of the main means of overcoming local resistance is the financial involvement of local stakeholders. An added benefit of this approach is that, at an early stage of the project, developers can learn from local stakeholders what the specific concerns of the local community are, so that they can take these concerns into account in the implementation of the project. Moreover, energy agencies could set up public information campaigns to inform stakeholders about the benefits and drawbacks of renewables, CHP and other forms of DG.

The following is a list of suggestions to project developers on how to involve local stakeholders in DG projects.

- Grant easier access to the financing scheme for local investors, by giving them favorable conditions. For instance, the minimum share can be lower for local developers than for outsiders, or they receive preferential dividends;
- Give site owners the opportunity to bring the site into the project as part of the equity instead of selling it;
- Offer local owners an arrangement where they obtain equity by contributing in kind instead of in cash (e.g., raw materials);Address local people and agencies when acquiring equity; and
- Involve non-governmental environmental organizations in the development process: ask them to approve a design and publicize it.

Grid Access

Non-discriminatory access to the grid and transmission and distribution services is fundamental to ensure that DG can compete with other sources of electricity on an equal basis. The pricing and regulation of connection to the grid and of transmission and distribution network services is therefore very important for the penetration of DG in the EU electricity market. DG often faces additional barriers relative to centralized plants. Many of the barriers faced by DG are related to the cost and procedures for connecting to the grid.

The attitude of transmission and distribution companies with respect to the connection of DG is largely determined by the incentives arising from price regulation. Most transmission and distribution companies in the EU are subject to price regulation. The price that can be charged for transmission and distribution in these regulatory models is based on the operational cost, the capital cost and an allowable return on capital. Thus, the main issues are how grid connections and reinforcements are incorporated in the rate base of grid companies, and how the cost of connections can be recovered. It is recognized that the connection of DG may also entail benefits to the system in the form of deferral of transmission and distribution network upgrades and expansion, decongestion, improved local reliability, and the provision of ancillary services to the grid. These benefits are not usually reflected in the grid charges.

Two methods to calculate connection charges can be used, each with different economic rationales. The first method, *shallow connection charges*, only accounts for the cost of line extension to the nearest connection point and the equipment needed to connect the line to the rest of the grid. The costs of additional changes to the grid are recovered by the grid operator through grid-use tariffs and are thus spread among all users. This method benefits DG by reducing uncertainty of DG cost.

The second method, *deep connection charges*, accounts for all the cost of connection of a generator into the network, including the cost of adjustments beyond the point of connection. The cost has to be independently assessed for each new generator. This second method is more complicated, because the location-specific cost of grid adjustments must be considered.

The EU identified, through the DECENT study, five general criteria for improving regulation with regard to grid access for DG. These are transparency, economic efficiency, effectiveness, equity, and predictability. These criteria can be put into practice in the following ways:

- Develop uniform technical standards for interconnection to the grid. This would reduce the scope for dispute on the technical requirements associated with grid connection;

- Develop transparent and efficient rules relating to the allocation of costs of technical adaptations, such as grid connections and grid reinforcements to all users of the grid, including future generators;

- Develop clear procedures and norms for dispute settlement in case of disagreement on the cost of connection;

- System operators should publicly provide an indication of favorable and problematic sites for grid connection based upon geographically differentiated price signals to DG project developers;

- Price and quality regulation should provide incentives to network companies to deal with connection requests in a fair and efficient manner. A network company should not have an economic incentive to avoid DG connection, and should be encouraged to take a proactive and service oriented stance towards facilitating DG connection; and

- Coordination between spatial planning, network planning and renewable energy sources (RES) interconnection. The interactions between these three are numerous and cross administrative levels. In order to achieve good coordination, effective cooperation between the administrative bodies, network companies and regulators, is necessary.

Market Access

Balancing and settlement systems serve to maintain system balance and to allocate the costs incurred in maintaining system balance. Each member of the electricity supply chain is responsible for balancing their own or another party's supply and consumption. This is referred to as balance responsibility. Failure to meet this balance responsibility results in penalty payments. The level of these penalty payments is often determined through a balancing market.

The main problems with DG in balancing and settlement systems occur with intermittent renewables – mainly wind – and heat-driven CHP. These technologies cannot always adjust their loads to match a pre-specified pattern. This unpredictability results in penalty payments for these sources in the settlement process, which in turn reduces the value of the electricity that is produced from these intermittent sources. This loss in value needs to be compensated through support mechanisms or in the market for renewable energy.

In the short term, priority dispatch can be implemented to reduce the cost of balancing and contracting to DG developers and operators. However, as more DG is connected the cost of this exemption from the balancing and settlement system to the rest of the system will rise.

Pilot Program Results

Many of the barriers identified in the DECENT project are in general terms addressed by current legislative proposals at the EU level, such as the proposed amendments to the Electricity and Gas Directives, the proposed CHP Directive and the Renewables Directive of 2001. The DECENT project has elaborated further with more practical recommendations on how to tackle the main barriers to DG within the framework of existing and developing EU legislation.

B.5 Japan[22]

Table B-5
Survey Summary – Japan

Approximately 14 percent of Japan's energy capacity comes from distributed generation. A survey by the Japan Engine Generator Association (NEGA) estimates that from 1997 to 2000, installation of distributed generation, excluding emergency power, grew by 2,418 MW, or about 11% of the amount installed by the utilities during the period. Distributed generation is recognized as a business opportunity. Japan has ten utilities; all are privately owned.

The Federation of Electric Power Companies of Japan (FEPC) consists of nine electric utilities that work together on supply and environmental issues.

Issue	Status
Siting and Permitting	Adjusted fire regulations and staffing requirements to assist DG permitting.
System Interfaces	Allows net metering for any solar installation.
Interconnection Standards	
LDC Ownership of DG	Eight of ten utilities created subsidiaries to offer DG services.
Stranded Costs	
System Investments	
Standby Charges	Established capacity charge that is high only when the utility power is actually used as a backup. The capacity charge (kW charge) is 110% of normal when power is used and only 30% of normal when not in use. The energy charge is 110% of normal if the use is planned and 125% of normal is unplanned.
Incentives for DG	Cogeneration incentives offered include high depreciation or initial tax credit coupled with low interest loans and subsidies up to 15 percent, depending non the use of heat.
Other Issues	Key problems with central power in Japan are transmission losses, investment risks and the possibility of earthquake damage. In 2003, the government established the Energy Masterplan, promoting the importance of development and widespread use of DG. DG is also featured in the government's Kyoto Protocol Target Achievement Plan. Principal issues that determine the generation portfolio in Japan: economically driven policy reducing the nation's dependence on crude oil and environmentally motivated resolution to reduce pollutant emissions in metropolitan areas. Another issue is the low price set for excessive energy to be bought by the LDC's

Approximately 12 percent of Japan's energy capacity comes from distributed generation. A survey by the Japan Engine Generator Association (NEGA) estimates that from 1997 to 2000, installation of distributed generation, excluding emergency power, grew by 2,418 MW, or about 11% of the amount installed by the utilities during the period. Distributed generation is recognized as a business opportunity for the utilities. Eight of

[22] *Distributed Generation in Liberalized Electricity Markets*, International Energy Agency, 2002.

the ten electric utilities in Japan have established subsidiaries to offer DG services. All ten utilities are privately owned.

The Federation of Electric Power Companies of Japan (FEPC) consists of nine electric utilities in Japan that work together on supply and environmental issues. For many years they have voluntarily promoted the use of renewable power through various measures, including offering to buy excess solar-generated power back from customers at current electricity rates and creating Green Power Funds to promote renewable energy use. In addition to these efforts, the FEPC are preparing to meet the accelerated pace of increases in the quotas that were introduced by the Kyoto Treaty in 2003, and are working to achieve the 2010 target of 12.2 billion kWh in Japan.

Current DG Approach, Incentives and Tariff Treatment

Key drivers of the adoption of distributed generation in Japan include high electric prices and limited market openings for electricity. There are three common types of DG in the country: oil-fired generation, designed principally to meet peak demand; oil-fired combined heat and power (CHP) using diesel engines and steam turbines; and gas-fired CHP with engines, gas or steam turbines. The high retail price of natural gas in Japan makes gas-fired distributed generation without CHP uneconomical. Gas-fired CHP is only marginally economical but is the only DG option available in Tokyo, Yokohama, and Osaka, due to tight environmental regulations.

The key problems with central power in Japan are transmission losses, investment risks and possibility of earthquake damage. In 2003, the Japanese government established the Energy Masterplan, describing the importance of development and widespread use of DG such as fuel cells, cogeneration, PV, wind, biomass and waste generation. DG also features significantly in the government's Kyoto Protocol Target Achievement Plan.

Japan has removed several regulatory barriers to encourage the development of distributed generation and, in particular, cogeneration systems. These actions include adjustments to fire regulations and onsite staffing requirements. However, some regulatory barriers still remain. Selling excess distributed generation to another electricity customer generally is not allowed. The costs of electrical protection equipment can be substantial: about 10% of the total cost of the facility or more.

Japan offers incentives for cogeneration, such as high depreciation or initial tax credit coupled with low interest loans and subsidies up to 15 percent, depending on the use of heat. Japan's capacity charges are high only when the grid energy is used in place of the DG unit. For instance, the capacity charge is 10 percent higher than usual when grid energy is used. In this case, the billing determinant is the actual non-coincident peak demand. All other times the capacity charge is only 30 percent of the normal, non-DG, rate (20 percent for industrial rates). The billing determinant is the contract demand. The energy charge is higher and depends on the type of energy use. The energy rate is 10 percent higher than normal for a planned use and 25 percent higher when unplanned.

Regulatory and Market Issues

Two principal issues determine the generation portfolio in Japan: economically driven policy reducing the nation's dependence on crude oil, and environmentally motivated resolution to reduce pollutant emissions in metropolitan areas. In addition, policies to develop nuclear power and to protect domestic refining have also influenced the portfolio of generation facilities.

Two oil shocks hit Japan, one in 1973 and one in 1979. Since then, the government has strongly advocated measures to avoid disruption in the supply of overseas crude oil. During the oil shocks, import prices of crude oil showed sudden spikes. Japan had no other recourse but to continue buying oil and consequently suffered with other oil-importing countries. During that time Japan was unable to reduce its petroleum consumption by even two percent. Japan's electric power sector relied heavily on petroleum as a generation resource, while pressures to increase electricity demand were stronger than ever. The national government instituted price controls and froze rates for public services, from railroad fees to standard prices of rice, for several months. The nine electric power companies suffered from the gap between increasing costs and depressed revenue from frozen electricity rates until the government agreed to increase the rates, then suffered from a decline in demand due to the rate increase.

With forecasts that crude-oil prices would continue to soar, petroleum no longer appeared to offer an attractive, economical generation resource for Japan's electric power sector; the sector therefore inclined toward substitute resources. In 1980, legislation established a guideline essentially prohibiting Japan's electric power sector from planning additional oil-powered generation units.

B.6 The Netherlands

Table B-6 Survey Summary – The Netherlands	
The Netherlands has an advanced restructured market where distributed generation is well established, principally because government policies have supported CHP and renewable energy sources. However, policies and tariffs are designed to avoid subsidizing the development of DG technologies.	

Issue	Status
Siting and Permitting	Developed rules for three generator categories (< 5 MW, 5 – 60 MW, and > 60 MW) and by voltage levels.
System Interfaces	Generation plants > 5 MW need to provide ancillary services except for plants with uncontrollable sources of energy, such as wind. Plants under 60 MW do not have as stringent ancillary service requirements as larger plants.
Interconnection Standards	Standardized interconnection code in place. Grid code, system code and Tariff code take into account different sizes of generators, although no distinction is made between DG and centralized generator.
LDC Ownership of DG	Utilities are purchasing and maintaining small CHP units at a customer site then selling the power and heat at reduced rates to the customer. Larger CHP units are co-operated.
Stranded Costs	Since all network costs are paid for by the LDC, stranded costs may exist.
System Investments	Generation facilities connected at less than 110 kV do not need to pay transmission costs based on the assumption that facilities connected at lower voltages bring efficiency to the system. Only "shallow" connection costs are paid by the DG facility owner.
Standby Charges	
Incentives for DG	Due to the restructuring of markets, new tariffs and reduced incentives reduce the implementation of CHP, although wind development is strong. Tax discounts are used as incentives for renewable resources and CHP. However, the minimum price for CHP output has been abolished.
Other Issues	20% of CHP plants were built for horticultural purposes. The major issues seen in the Netherlands is low electricity prices, connection charges, higher gas prices cause issues for CHP plants. However, wind capacity is growing by approximately 10% per year.

The Netherlands has an advanced restructured market where distributed generation is well established, principally because government policies have supported CHP and renewable energy sources. However, policies and tariffs are designed to avoid subsidizing the development of DG technologies[23].

Current DG Approach, Incentives and Tariff Treatment

Interconnection rules in the Netherlands are standardized. Market rules were adjusted soon after their introduction so that CHP producers could more accurately predict how

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[23] International Energy Agency, *Distributed Generation in Liberalised Electricity Markets*. OECD/IEA 2002

much electricity to supply to the grid. Power parks have been established where the main producer is the only customer with a direct connection to the grid.

Case Study: The Netherlands

In the Netherlands, only about 3% of homes are served by district heating. CHP, which accounts for 52% of electricity generation, is used in industry, horticulture, apartments, nursing homes, swimming pools and hospitals. Most applications use natural gas but biomass is increasingly used in newer installations.

CHP has grown substantially in the Netherlands since the 1980s through the introduction of subsidies, tax advantages and regulatory preferences that recognize its potential contribution to reducing CO2 emissions. These have included – investment subsidies and tax deductions, particularly for small scale CHP and biomass CHP – exemptions from, or reductions in, energy and environmental taxes for CHP and renewable energy schemes – lower charges on grid connection and system use – modifications to the electricity trading system, including more favorable terms for generators selling surplus electricity back to the grid.

Other factors have also been important. High heat load demands in industry, agriculture and horticulture make CHP a particularly cost-effective energy source. Industry considers CHP a cost-effective tool enabling them to deliver on the CO2 reduction commitments agreement with the Government. Finally, controls on the development of large scale generation combined with the relaxing of market rules to permit large users of energy to build their own CHP plants or import electricity from elsewhere have meant that energy distributors or suppliers have started to offer CHP to customers, providing financing where necessary.

Source: DTI-Ofgem

Regulatory and Market Issues

The deregulation of the supply market for all customers started in 2004.

Small generators are treated differently from large generators in a few ways. There are different rules for generators based on the size classification of the generating unit. Size categories are[24]:

- Less than 5 MW;
- 5 MW – 60 MW; and
- Greater than 60 MW.

For example, large units need to provide secondary control power, while units below 60 MW can choose whether or not to provide backup. All generating plants with capacity greater than 5 MW are required to contribute to the frequency control, although the actions required by units less than 60 MW are less restrictive.

In addition, generation units connected to the low voltage network are treated differently than units connected to the transmission grid. For example, only generating plants connected to the transmission grid must pay a transmission charge. The DG developer only pays connection charges based on the cost to hook up to the system. Any additional costs upstream due to addition of the DG facility to the system are paid by the utility.

For smaller CHP units, the utilities often invest in and maintain the unit, while the energy user is supplied with heat and energy at a reduced price. Under this scheme the utility

[24] KEMA Limited, *Survey Study of Status and Penetration Levels of Distributed Generation (DG) in Europe and the US (Stage One).* Department of Trade and Industry, 2003.

takes most of the risk. For larger CHP projects, utilities and end-users cooperate on a more equal basis. Often a joint venture is set up to operate the CHP units and share risks and profits.

CHP producers still face difficulties because of rising gas prices and falling electricity prices. To help them cope, the Dutch government has increased direct subsidies to producers and has encouraged distribution companies to ensure that the network value of distributed generation is appropriately reflected in tariffs. Subsidies have been provided to "efficient" CHP units as a discount on the tax of generated energy. Carbon dioxide-free discounts have been provided as well.

B.7 New Zealand

Table B-7
Survey Summary – New Zealand

The Electricity Commission was set up under the Electricity Act to oversee New Zealand's electricity industry and markets. It began operating in September 2003. The Electricity Commission regulates the operation of the electricity industry and markets, to ensure electricity is produced and delivered to all consumers in an efficient, fair, reliable and environmentally sustainable manner. The Commission also promotes and facilitates the efficient use of electricity.

Issue	Status
Siting and Permitting	Fees and requirements vary by size of the DG unit. (< 10 kW, 10kW – 1 MW, 1MW – 5MW, > 5 MW)
System Interfaces	The Retailer (LDC) must have standard terms and conditions on which it will offer to pay for electricity exported to a distribution network from equipment capable of generating no more than 40,000 kilowatt hours of electricity over a year. Generally, generators < 10 MW do not have to bid into the market on a day-ahead basis.
Interconnection Standards	No consistent nationwide standard. Connection is LDC specific.
LDC Ownership of DG	
Stranded Costs	
System Investments	
Standby Charges	
Incentives for DG	
Other Issues	Continued exploration by jurisdiction. Government Policy recognizes the benefit of DG: ■ Meeting demand goals ■ Security of energy supply ■ Reduce losses & deferred network investments ■ Climate benefits ■ Increase competition drive a well established market.

The Electricity Commission[25] was set up under the Electricity Act to oversee New Zealand's electricity industry and markets. It began operating in September 2003. The

[25] New Zealand Electricity Commission: http://www.electricitycommission.govt.nz/aboutcommission/

Electricity Commission regulates the operation of the electricity industry and markets, to ensure electricity is produced and delivered to all consumers in an efficient, fair, reliable and environmentally sustainable manner. The Commission also promotes and facilitates the efficient use of electricity.

The three priorities of the Electricity Commission, as established by the government, are:

- Security of supply and reserve generation;
- Priority investment in the transmission grid; and
- Hedge market arrangements and demand-side participation.

The Commission is governed by an executive chair and four other members appointed by the Minister of Energy. The Commission has a team of about 40 staff.

Current DG Approach, Incentives and Tariff Treatment

The Electricity Commission has established the following model contract guidelines for distributed generation[26]:

- The Retailer must have standard terms and conditions on which it will offer to pay for electricity exported to a distribution network from equipment capable of generating no more than 40,000 kilowatt hours of electricity over a year. The obligation applies:

    - only in respect of distribution networks to which customers to whom the Retailer supplies electricity are connected; and
    - irrespective of whether the person generating the electricity is or becomes a customer to whom the Retailer supplies electricity.

- DG terms must reflect the reasonable expectation of customers.

- The Retailer may develop its own DG terms. However, any DG terms developed by the Retailer cannot be less favorable to customers than those the Electricity Commission considers reflect the reasonable expectations of customers.

- In accordance with the objective of facilitating distributed generation, the Retailer must have publicly available at its offices or through its website or some other readily accessible means, the following information:

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[26] *Facilitating Distributed generation*. Resources & Networks Branch, Ministry of Economic Development, September 2006.

- the Retailer's criteria for entering into DG terms;
- the Retailer's DG terms; and
- the price or prices the Retailer will pay to a customer for electricity exported by the customer.

B.8 United Kingdom

Table B-8
Survey Summary – United Kingdom

The United Kingdom (UK) has policies that favor development of CHP and renewables as well as the advancement of a deregulated market. The government has set targets for increasing the contributions of renewables, from around 2 percent in 2000 to 10 percent by 2010, and CHP, from 4.6 GW to 10 GW by 2010.

Issue	Status
Siting and Permitting	Systems under 50 MW do not require a license to operate.
System Interfaces	The Government is reluctant to introduce net metering due to potential complications in paying and refunding the value added tax that is payable on electricity. Pilot programs are under way in some areas.
Interconnection Standards	DTI published Technical Guide to the Connection of Generation to the Distribution Network. In addition, Engineering Recommendations G75/1, G59/1 and G83/1 refer to the connection of >5 MW or >20 kV systems, <5MW at ≥20 kV, and small scale generators up to 16A per phase at low voltage, respectively.
LDC Ownership of DG	LDC's can not own generation equipment.
Stranded Costs	Stranded costs are addressed in modeling used to calculate Transmission Use of System (TUoS) and Distribution Use of System (DUoS) charges.
System Investments	Employs locational transmission charges based on where the generation is located, determined by the forward looking long run marginal costs of providing incremental capacity at different points on the network.
Standby Charges	Standby charges are assessed based on the distribution system costs through a Generator Distribution Use of System (GDUoS) charge, modeled by region within a utility's territory.
Incentives for DG	Ofgem incentives include: ■ A £/kW incentive and guaranteed cost recovery to encourage the distribution network operators to connect DG; ■ New mechanisms to encourage innovation, both generally and specifically in generation connections; ■ Strengthening the losses incentive, encouraging LDCs to reduce losses; ■ LDCs to develop charging models that reflect the benefits and costs of DG; ■ Increased flexibility to fund transmission investment; ■ Open debate on smart metering, which could be of benefit to small DG; and ■ Ofgem has proposed to remove the "28 day rule" (the requirement that suppliers should allow consumers to terminate supply contracts at 28 days notice).
Other Issues	The British Government has four long-term goals for energy policy: ■ To cut carbon dioxide emissions (60 percent by about 2050, with real progress by 2020); ■ To maintain reliable energy supplies; ■ To promote competitive markets, helping to raise the rate of sustainable economic growth and to improve productivity; and ■ To ensure every home is adequately and affordably heated.

The United Kingdom (UK) has policies that favor development of CHP and renewables as well as the advancement of a deregulated market. The government has set targets for increasing the contributions of renewables, from around 2 percent in 2000 to 10 percent by 2010, and CHP, from 4.6 GW to 10 GW by 2010[27].

The government has also identified the development of distributed generation as an important way to increase competition among electricity producers. However, electricity trading rules established in 1998, known as the New Electricity Trading Arrangements (NETA), have been disadvantageous to small DG operators. The rules require that all generators predict their output at least 3.5 hours in advance of actual production. They face penalties if they produce less than the forecast, but receive only modest reward for supplying more than predicted. So far NETA has resulted in a drop in electricity prices and a decline in power produced for the grid by distributed generators. In anticipation of these problems, the government commissioned an Embedded Generation Working Group to examine the role of DG. The group's report[28], issued in January 2001, identified a number of practical measures to ensure DG is integrated into the power system in an economically efficient way. The government and the regulator the Office of Gas and Electricity Markets (Ofgem) have both acted on the report's recommendations by:

- Proposing new principles for setting tariffs and simpler rules for grid connection;
- Requiring distributors to provide additional information on the value of distributed generation at different points in their grid; and
- Establishing a Distributed Generation Coordinating Group to follow up on the Working Group's recommendations.

Ofgem's first priority is the protection of consumers by promoting effective competition and regulating the gas and electric utilities. Other priorities include securing Britain's energy supply, helping markets achieve environmental improvements efficiently, and account for the needs to the country's most vulnerable customers. The agency is funded by the energy companies who are licensed to run the gas and electricity infrastructure.

Current DG Approach, Incentives and Tariff Treatment

The British Government has four long-term goals for energy policy as stated in the 2006 Energy Review[29]:

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[27] *Planning Policy Statement: Renewable Energy*. Office of the Deputy Prime Minister, 2004.

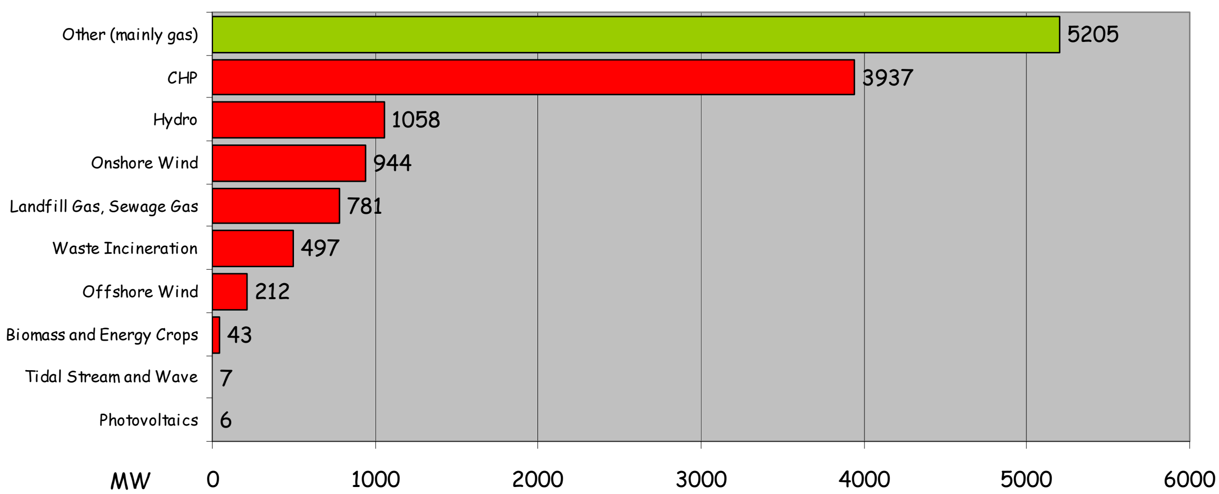
[28] *Embedded Generation Working Group: Report into Network Access Issues.* Department of Trade & Industry (DTI), January 2001.

[29] *Our Energy Challenge: Securing clean, affordable energy for the long-term*. DTI, January 2006

- To cut carbon dioxide emissions (60 percent by about 2050, with real progress by 2020);
- To maintain reliable energy supplies;
- To promote competitive markets, helping to raise the rate of sustainable economic growth and to improve productivity; and
- To ensure every home is adequately and affordably heated.

The chart below shows the electricity generation plants currently connected to UK distribution networks:

Figure B-3
Generation Connected to UK Distribution Networks



Source: DTI Energy Review (2006)

Ofgem recognized that a key challenge was to adapt the regulatory framework to accommodate the expected increase in distributed generation. This led to a number of policy developments. Specific incentives offered by Ofgem include:

- New incentives to encourage the distribution network operators to connect distributed generators, with a £/kW incentive and guaranteed cost recovery;
- New mechanisms to encourage innovation, both generally and specifically in generation connections;
- Strengthening the losses incentive, which encourages distributors to reduce losses from their system;
- Changing the way distributed generators are charged for connection to, and use of, the system;

- Ofgem is pressing the distribution companies to develop charging models that reflect the benefits and costs of distributed generators;

- Ofgem has also taken steps to provide increased flexibility to fund transmission investment – re-opening the previous transmission price control and proposing revenue drivers in the current review. Transmission reinforcement is needed to accommodate the significant renewable generation planned in Scotland, whether distribution or transmission connected;

- Ofgem has taken an active lead in the debate on smart metering, which could be of benefit to smaller scale distributed generation;

- Ofgem has proposed to remove the "28 day rule" (the requirement that suppliers should allow consumers to terminate supply contracts at 28 days notice), which was seen as a barrier to the development of energy services products; and

- More generally, Ofgem has sought to improve the accessibility and transparency of market information. Distribution companies are now required to publish long-term development statements. Contractual arrangements for use of the distribution system have been harmonized and more flexible governance introduced.

The United Kingdom has adopted a locational charging methodology for its transmission system[30]. This means that charges vary depending on where a generator is putting energy onto the network, and depending on where a supplier is taking energy from the transmission network. The basic premise behind locational charging is that generators farthest away from centers of demand (and suppliers farthest away from centers of generation) make most use of the transmission system – and therefore should make a larger contribution to the total costs of the transmission system.

Charges are based on the forward-looking, long-run marginal cost of providing incremental capacity at different points on the network, adjusted for voltage, and security. The charges reflect the fact that, because of the existing pattern of power flows over the network and prevailing pattern of demand and generation, locating in some places will cause higher reinforcement costs than at others. Therefore, locating at certain points may reduce or defer the need for reinforcement and therefore reduce the total costs of the network.

[30] UK Transmission Charges by zone: http://www.nationalgrid.com

Regulatory and Market Issues

The UK's policy is requires a license in order to participate in the electricity sector. Therefore, all the major electricity generators, energy suppliers and network operators must obtain a license to operate in their part of the market. Licensing helps to ensure consumer choice and offers consumer protection while also ensuring resilient and efficient networks.

The re-emergence of smaller, distributed sources of generation over the last 15 years has been accommodated within the market, in part by exempting many of them from the need to hold a generation license, as generators under 50 MW are allowed a "class exemption" to the license requirement. Several important issues have surfaced regarding the unlicensed distributed generators.

- Embedded benefits – DG owners have a shorter delivery path to customers, where the energy is not subject to a transmission charge. An energy supplier effectively reduces the overall charges by purchasing DG; and

- Licensing of DG – the government must balance the need to minimize the regulatory burden on smaller operators against the need to protect reliability and integrity of the overall network.

It is recognized that Ofgem has a direct impact on DG through its regulation of distribution and transmission licensees, and an indirect impact through its regulation of the markets for gas and electricity.

Ofgem is also working on developing enduring charging arrangements for distributed generation. With the trend of increasing distributed generation connected to the network, it is likely that distribution networks will increasingly export power onto the transmission system at certain times, rather than consistently take power from it. It has been found that a number of parties are not paying for the use they make of the transmission network. If distributed generators are not facing the full charges they impose, then inefficient decisions are likely to be taken regarding the use of the network, and the additional costs will ultimately be paid by consumers.

Pilot Program Results

In 2006, Ofgem established an industry group – the Transmission Arrangements for Distributed Generation (TADG[31]) working group to work up options for the appropriate development of transmission arrangements to reflect the impact of distributed generation

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[31] Hull, Robert, *Transmission Arrangement for Distributed Generation (TADG) Working Group: Invitation and draft terms of reference*. Ofgem, June 2006

on the transmission network. The purpose of the group is to identify options for change to the transmission arrangements as they affect distributed generation in light of the following criteria.

- Minimizing implementation costs. The arrangements should not impose undue implementation or administrative costs on industry participants, recognizing that such costs might be passed on to consumers.

- Cost reflectivity. The arrangements should seek to reflect the costs that industry participants impose on the system. Cost reflective charges promote effective competition between industry participants and facilitate market entry.

- Efficient network development. Arrangements should encourage efficient decisions regarding the development and use of the transmission and distribution networks.

In developing these options, key questions the group is considering are as follows.

- To what extent is the impact (flows, operation, investment and associated costs) of distributed generation on Great Britain's transmission system the same as that of transmission connected generation?

- Are the existing transmission access products appropriate to distributed generators, is there merit in considering access products based on the export to Great Britain's transmission system rather than the full capacity of the generator?

- If a distributed generator does not have firm transmission rights, then how can its export to Great Britain's transmission system be controlled? Can this be achieved through the Distribution Network Operator or the supplier?

Case Study: London, England

The Greater London Authority has put in place a number of measures to support the development of DG. The London Plan now requires new developments to consider combined heat and power (CHP) and heat-fired absorption cooling, and to produce 10% of energy needs from on-site renewables. Requirements currently under consideration increase the on site renewable energy to 20% as part of the Climate Change and Energy Strategy for London. One of the key features of the London system will be the use of private wire networks to maximize the economic benefits of DG and microgeneration.

The London Climate Change Agency (LCCA) is a municipal company owned by the London Development Agency and led by the Mayor, implementing projects that impact climate change, especially in the energy, transport, waste and water sectors. The Mayor's Energy Strategy for London includes a target of reducing carbon dioxide (CO_2) emissions by 20%, relative to the 1990 level, by 2015, as the crucial first step on a long-term path to a 60% reduction from the 2000 level by 2050. One of the key projects of the LCCA was the establishment of the London ESCO Ltd, a public/private joint venture Energy Services Company between the LCCA Ltd and EDF Energy plc, incorporated in 2006.

The London ESCO will implement low carbon DG projects across London on a commercial basis. The London ESCO has been established to deliver low carbon decentralized energy solutions in new and existing developments. Initially, the focus will be on cogeneration (heat and power), trigeneration (heat, power and heat-fired absorption cooling) and integrated renewable energy on local private wire district energy systems and networks but will also include special projects such as fuel cells, environmentally friendly waste to energy technologies, renewable gases and biomass fuels. The London ESCO schemes will maximize the direct retailing of electricity, heating and cooling over private wire decentralized energy networks. Surplus electricity will also be traded between sites using an enabling agreement for exempt supplier operation.

Source: London Climate Change Agency, DTI, Ofgem

B.9 United States

The U.S. is primarily dominated by large generation and supply companies. Cogeneration and DG markets experienced growth during the late 1990s. Growth slowed in 2002 when gas prices increased dramatically. At the national level, the Federal Energy Regulatory Commission (FERC) has adopted standards for units under their jurisdiction. The Energy Policy Act of 2005 includes requirements that all states consider updating their interconnection standards and other provisions favorable to DG. The U.S. intends to raise cogeneration levels to 92 gigawatts (GWe) by 2010.

Key barriers in the U.S. include long-term coal contracts that have delayed coal price increases to the utilities, high gas prices and volatility discouraging the use of gas-fired CHP, interconnection barriers and state bans on third party generation, bans on private wires crossing public streets, and emission standards that do not reflect the efficiency of cogeneration.

The key drivers for promoting DG are aggressive cogeneration goals set by the Department of Energy (DOE) and Environmental Protection Agency (EPA), state promotion of competition, increased outages and rising power prices, national security concerns over system reliability, and the promotion of renewable and advanced energy standards.

California

Table B-9a
Survey Summary – United States, California

The State of California is very proactive in adopting policies and standards that promote renewable energy and aid in the adoption and promotion of distributed generation technologies. Three state agencies are active in promoting adoption of DG through standardizing the application and certification process.

- California Air Resources Board (CARB)
- California Energy Commission (CEC)
- California Public Utilities Commission (CPUC)

Issue	Status
Siting and Permitting	CA does not have a separate Generator class. CA has established a number of permit streamlining processes to encourage DG, following a December 2000 report "Distributed Generation: CEQA Review and Permit Streamlining". Streamlining activities adopted by the state include: ■ All permit applications can be submitted at one time. ■ The State Permit Streamlining Act provides time limits for environmental studies.
System Interfaces	Net metering is offered by utilities in CA.
Interconnection Standards	CA has adapted IEEE Interconnection Standard 1547 specifically for the state of CA and called this standard Rule 21. A Rule 21 working group was established and the group continues to address specific details of the standard.
LDC Ownership of DG	LDC's are not permitted to own generation equipment
Stranded Costs	The CPUC has approved tariffs designed to collect a surcharge from customer generation departing load (see Rulemaking 03-09-029).
System Investments	Rulemaking 04-04-025 was opened to determine a methodology for quantifying avoided costs that are both time and region specific.
Standby Charges	If a DG unit in California is down and the customer is able to immediately reduce its load, standby costs are minimal. Standby rates were recently updated by the three private utilities. Standby charges are divided in to three categories: ■ Supplemental – portion of load not covered by DG is at the applicable tariff. ■ Backup – unanticipated load results in increased costs. ■ Maintenance – scheduled at times of utility low demand, costs should reflect this flexibility.
Incentives for DG	CA has established a number of permit streamlining processes to encourage DG, following a December 2000 report "Distributed Generation: CEQA Review and Permit Streamlining". Streamlining activities adopted by the state include: ■ California Solar Initiative – 10 year, \$2.8 billion program with a goal to increase installed rooftop solar capacity by 3,000 MW by 2017. ■ Self Generation Incentive Program – provides incentives to DG systems meeting or exceeding CARB emission standards through 2012. ■ Renewable Portfolio Standard – 20 percent renewable target by 2010.
Other Issues	In 2002, the CEC adopted a *Strategic Plan for Distributed Generation*. The plan is designed to serve as a guidance document for the coordination of activities related to the deployment of DG in the State of California. DG is a priority

The State of California is very proactive in adopting policies and standards that promote renewable energy and aid in the adoption and promotion of distributed generation technologies. Three state agencies are active in promoting adoption of DG through standardizing the application and certification process. The three agencies are described below.

- *California Energy Commission* – The California Energy Commission is an energy policy and planning agency created by the state legislature in 1974 to forecast future energy needs and keep historic energy data, license thermal power plants 50 MW and greater, promote energy efficiency through appliance and building standards, develop energy technologies, support renewable energy, and plan for and direct state response to energy emergencies.

- In addition, the Energy Commission is responsible for overseeing funding programs that support public interest energy research (PIER Program), advance energy science and technology through research, development and demonstration, and provides market support to existing, new, and emerging renewable technologies.

- *California Air Resources Board* – The California Air Resources Board is part of the California EPA. The mission is to promote and protect public health, welfare and ecological resources through the effective and efficient reduction of air pollutants while recognizing and considering the effects on the economy of the state.

- *California Public Utilities Commission* - The California Public Utilities Commission (CPUC) regulates privately owned telecommunications, electric, natural gas, water, railroad, rail transit, and passenger transportation companies.

Current DG Approach, Incentives and Tariff Treatment

California is active in promoting distributed generation technologies through various incentive-based programs, described below.

<u>California Solar Initiative Program</u>

The California Solar Initiative (CSI) is a 10-year, $2.8 billion program that provides incentives in order to develop a self-sustaining solar market. The initiative was approved by the California Public Utilities Commission (CPUC) in January of 2006. The goal of the program is to increase the amount of installed solar capacity on rooftops in the state by 3,000 MW by 2017.

Funds will come primarily from electric and gas distribution customers of investor-owned utilities, and will go toward the installation of photovoltaics (PV) under 5 MW capacity initially, with solar hot water heating, and solar thermal heating and cooling systems being added at a later date.

The Energy Commission will oversee the program component that focuses on solar installations in the residential new construction market. The CPUC will oversee the remainder of the CSI, which will cover existing residential housing, as well as existing and new commercial and industrial properties.

Self-Generation Incentive Program

Assembly Bill (AB) 2778, Chapter 617, Statutes of 2006 requires the Public Utilities Commission, in consultation with the Energy Commission, to administer, until January 1, 2012, a self-generation incentive program for distributed generation resources and limit eligibility for non-solar technologies to fuel cells and wind technologies that meet or exceed the emissions standards adopted by the Air Resources Board. This bill requires the Energy Commission, by November 1, 2008, in consultation with the Public Utilities Commission and Air Resources Board, to evaluate the costs and benefits of providing ratepayer subsidies for renewable and fossil fuel "ultra-clean, low-emission distributed generation" as part of the Energy Commission's Integrated Energy Policy Report.

Renewable Portfolio Standard

The newly revised Renewable Portfolio Standard (RPS) calls for a 20 percent renewable energy target by 2010.

Case Study: California

The Pasadena Water & Power company suggested that one possible way for a college to reduce energy costs would be to generate some of their own power. Utilizing combined heat and power was also suggested, primarily because of the 750,000-gallon swimming pool that is maintained at 81°F. The solution was to install two Capstone 60 kW microturbines with heat recovery. The amount of heat recovered from the microturbines was enough to heat the pool and displace the original heaters. The result was they are using about the same amount of gas to run the microturbines as they were to heat the pool, but they are creating an extra 120 kW of power. The resulting electricity cost savings to the college is about $100,000 per year.

Source: California Energy Commission

Regulatory and Market Issues

The Energy Commission has adopted standard interconnection requirements as California Rule 21, which is modeled after the IEEE Interconnection Standard 1547. An Interconnection Working Group has been established to review and refine Rule 21 to meet the needs of utilities and customers in California.

Additional work regarding standby charges and policies affecting DG includes CPUC rulemaking R.99-10-025. The purpose of the rulemaking was to develop specific policies and rules to facilitate the deployment of DG in California. In its Interim Decision Adopting Standby Rate Design Policies (D.01-07-027) issued on July 12, 2001, the commission determined that "most of the distribution system costs to serve standby customers appear to be fixed in nature." The commission makes a distinction of physical assurance, where a site is able to immediately reduce all or part of the load served by the DG unit when the DG unit is not operating. A site capable of physical assurance would not be responsible for the fixed costs associated with the utility providing physical assurance.

Three types of standby service were identified: supplemental, backup, and maintenance[32].

- Supplemental – utility supplies a portion of the customer's load that is not regularly supplied by the DG unit. This supplemental load is treated according to the customer's otherwise-applicable tariff.

- Backup – this service is unanticipated and will result in a higher cost to the customer.

- Maintenance – this service can be scheduled during periods of utility low peak demand and costs should reflect this flexibility.

All three regulated utilities filed rate cases with the CPUC updating the standby charges. The CPUC has also implemented an exemption from paying exit fees for certain DG resources based on their emission characteristics.

New York

Table B-9b
Survey Summary – United States, New York

A number of entities within the state of New York strongly support the advancement of DG technologies. The agencies include:

- New York State Public Service Commission (PSC)
- New York State Energy and Research Development Authority (NYSERDA)
- New York Power Authority (NYPA)

Policy is primarily set by the Public Service Commission. NYSERDA and NYPA are active in promoting DG through funding demonstration installations and advancing technology.

Issue	Status
Siting and Permitting	NY does not have a separate electric Generator class. However, the PSC requires gas companies to provide a separate rate class for DG users.
System Interfaces	Net metering is available in New York.
Interconnection Standards	The Public Service Commission has approved standardized interconnection requirements for DG units 2 MW or less connected in parallel with the utility distribution system. The PSC also publishes a list of pre-certified interconnection equipment to streamline the process.
LDC Ownership of DG	LDC's are not permitted to own generation equipment

[32] See Section 6.0, Standby Rate Design Issues, for more information.

Table B-9b Survey Summary – United States, New York	
Stranded Costs	In NY, exit fees are assess to departing load that will be served by DG systems in order to recover stranded costs. Exit fee exemptions are in place for loads that are replaced by clean on-site generation, such as CHP and renewables.
System Investments	
Standby Charges	New York agreed on a standard method to compute standby charges containing two demand charges. ▪ Contract demand – based on dedicated facilities applicable primarily to the DG customer. ▪ Daily as-used demand – based on shared facilities and the customer's daily maximum kW demand.
Incentives for DG	NY incentives for DG include: ▪ Distributed Generation and Combined Heat and Power (DG-CHP) Program - $15 million annual funding for development and demonstration of DG, CHP and supporting components for industrial, municipal, commercial and residential applications. ▪ NYSERDA PV Incentive Program – Maximum of 50 kW PV systems receive $4.00/watt to $4.50/watt rebate up to 60 percent of total installed cost. The $22.9 million program runs through 2007. ▪ Solar, wind and biomass energy systems are exempt from property taxes for 15 years in residential, commercial, industrial and agriculture sectors. Must be built prior to 2011.
Other Issues	New York government agencies are actively installing DG, with NYPA installing 24 solar projects totaling over 630 kW of capacity. Projects in progress in 2006 will increase the capacity by an additional 47 kW.

A number of entities within the state of New York strongly support the advancement of DG technologies. The agencies include:

- New York State Public Service Commission (PSC) - The New York State Public Service Commission (PSC) regulates electric, gas, steam, telecommunications, and water utilities in New York. The PSC also oversees the cable industry. By law the commission is responsible for setting rates and ensuring that adequate service is provided by New York's utilities. In addition, the PSC maintains jurisdiction over the siting of major gas and electric transmission facilities and has responsibility for ensuring the safety of natural gas and liquid petroleum pipelines.

- New York State Energy and Research Development Authority (NYSERDA) - In 1975, NYSERDA was created to promote energy efficiency and environmental protection through advanced energy and DER RD&D projects. NYSERDA derives its basic research revenues from an assessment on the intrastate sales of New York State's investor-owned electric and gas utilities, and voluntary annual contributions by the New York Power Authority and the Long Island Power Authority.

- New York Power Authority (NYPA) – NYPA is a state-owned power organization that operates 18 generating facilities and more than 1,400 circuit-miles of transmission lines. NYPA is actively demonstrating practical uses of solar photovoltaic systems and fuel cell power plants.

Policy is primarily set by the Public Service Commission. NYSERDA and NYPA are active in promoting DG through funding demonstration installations and advancing technology.

Current DG Approach, Incentives and Tariff Treatment

The Public Service Commission has approved standardized interconnection requirements for DG units 2 MW or less connected in parallel with the utility distribution system. A manual, dated 2005, contains steps to the interconnection application process, detailed technical requirements and standardized interconnection contracts and application forms. The PSC also publishes a list of pre-certified interconnection equipment to streamline the process.

In 2001 the PSC approved Guidelines for the Design of Standby Service Rates[33], establishing state-wide guidelines on the design of standby rates. The commission approved joint proposals for standby tariffs in compliance with the guidelines from six electric companies in 2002 and 2003. In 2004 the PSC refined the policies on the phase-in period for DG to shift to full standby service rates and DG criteria related to exemption from standby rates in utility-specific proceedings. Exemptions include small residential and non-demand commercial and industrial customers through 2009. In addition, customers whose DG capacity is less than 15 percent of the customer's maximum demand are exempt from the standby rate.

Standby rates are cost-based and include a customer charge, a fixed contract demand charge, and a variable as-used demand charge[34]. The contract demand charge recovers the costs of local facilities that are attributed exclusively or nearly exclusively to the customer involved. The daily as-used demand charge recovers costs associated with shared facilities, which apply to the customer's daily maximum metered demand that occurs during the utility's system peak periods.

Regulatory and Market Issues

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[33] Case 99-E-1470, *Insuring Into the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service.*

[34] See Section 6.0, Standby Rate Design Issues, for more information.

The PSC has used a combination of generic proceedings and utility-specific proceedings to develop its policies. Joint standby rates workshops are held with the PSC and NYSERDA.

In May 2003, the PSC initiated another DG proceeding (Case 03-E-0640[35]) to investigate whether current electric delivery tariffs present disincentives to DG, renewable technologies, or energy efficiency. The commission seeks to align current rate incentives and delivery rate structures with policy goals. Comments were compiled in 2004 and utilities moved toward cost-based rates, avoiding volumetric (per kWh) charges and basing rates on capacity or demand (kW) charges. In 2006 the inquiry expanded to include gas companies and opened for a second round of comments.

Case Study: Distributed Energy in New York

A 200-kilowatt (kW) fuel cell power plant is located in Yonkers, Westchester County, and runs on a waste gas created at a wastewater treatment plant, producing electricity through a chemical reaction rather than combustion. The gas used by the fuel cell is primarily methane and carbon dioxide. The Yonkers fuel cell helps avoid flaring (or burning off) of the potentially harmful waste gas, reducing emissions to the air with the added benefit of creating electricity.

The environmental benefits of fuel cells are significant. For example, the 200-kW fuel cell in Yonkers generates about 1.6 million kWh of electricity a year, and in that time releases 72 pounds of emissions to the environment. This compares with average emissions of about 41,000 pounds produced by coal- and oil-fueled plants generating the same amount of electricity.

Source: New York Power Authority

Pilot Program Results

In 2001, the New York State Public Service Commission issued an order approving a pilot program for the use of DG in the utility distribution system planning process following the adoption of standardized interconnection requirements for DG.

NYPA has been involved with the installation of 24 solar projects totaling over 630 kW capacity. Projects in progress in 2006 will increase the capacity by an additional 47 kW. In addition to the programs aimed at DG installation, the CHP Program and Landfill Gas to Energy Program also provide assistance.

- Combined Heat-and-Power (CHP) Program — combined heat-and-power, or cogeneration, technologies produce electricity and meet thermal energy needs (heat, hot water, steam, heating and cooling) simultaneously at the point of use. By contrast, conventional generation discards much of the heat generated in production. In addition to its increased efficiency, CHP offers numerous other advantages, including reduced energy costs, reduced emissions and improved reliability. We are currently working with the New York State Office of General

[35] New York Public Service Commission, Case 03-E-0640, *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation*.

Services and the State University of New York to install CHP systems at several of their facilities.

- Landfill Gas to Energy Program— NYPA is working with various counties and municipalities in New York State to implement landfill gas-to-electric energy projects. Using internal combustion engines, these projects have the potential to economically recover a total of close to 20 megawatts of electricity from waste gas. They will be owned and operated by the counties, municipalities or other public entities.

Texas

Table B-9c
Survey Summary – United States, Texas

The Public Utility Commission of Texas (PUCT) is responsible for the following.

- Regulating rates and terms for intra-state transmission service and for distribution service in areas where customer choice has been introduced.
- Oversight of the ERCOT market, including market monitoring and the ERCOT administrative fee.
- Adopting and enforcing rules relating to retail competition.
- Licensing of retail electric providers and registration of power generation companies, power marketers and aggregators.
- Reviewing proposals for the construction of new transmission facilities.
- Regulation of rates and service for integrated utilities.

Issue	Status
Siting and Permitting	In Texas, systems 1 MW and greater that do not sell power on the wholesale market can register as a self generator, simplifying the application and certification process.
System Interfaces	The PUCT has initiated a proceeding to consider net metering, time-based pricing, metering, communications (smart metering), and interconnection standards per amendments to the Public Utilities Regulatory Policy Act (PURPA) that were enacted in 2005 as a part of the Federal Energy Policy Act.
Interconnection Standards	The PUCT has adopted Substantive Rules §25.211, *Interconnection of On-Site DG*, and §25.212, *Technical Requirements for Interconnection and Parallel Operation of On-site DG*. The PUCT published a DG interconnection manual in 2002 to guide the inclusion of DG in to the Texas distribution system.
LDC Ownership of DG	LDC's are not permitted to own generation equipment
Stranded Costs	Recovery of stranded costs through competitive transition charges (CTC's) have expired.
System Investments	
Standby Charges	
Incentives for DG	Renewable energy system property tax exemption for the residential, commercial and industrial sectors.
Other Issues	According to the PUCT, more than 300 MW of DG is interconnected to the distribution system. Texas is actively involved in emission regulation, however, is considering exemptions for units less than 100 kW.

The Public Utility Commission of Texas (PUCT) is responsible for the following.

- Regulating rates and terms for intra-state transmission service and for distribution service in areas where customer choice has been introduced.
- Oversight of the ERCOT market, including market monitoring and the ERCOT administrative fee.
- Adopting and enforcing rules relating to retail competition.
- Licensing of retail electric providers and registration of power generation companies, power marketers and aggregators.
- Reviewing proposals for the construction of new transmission facilities.
- Regulation of rates and service for integrated utilities.

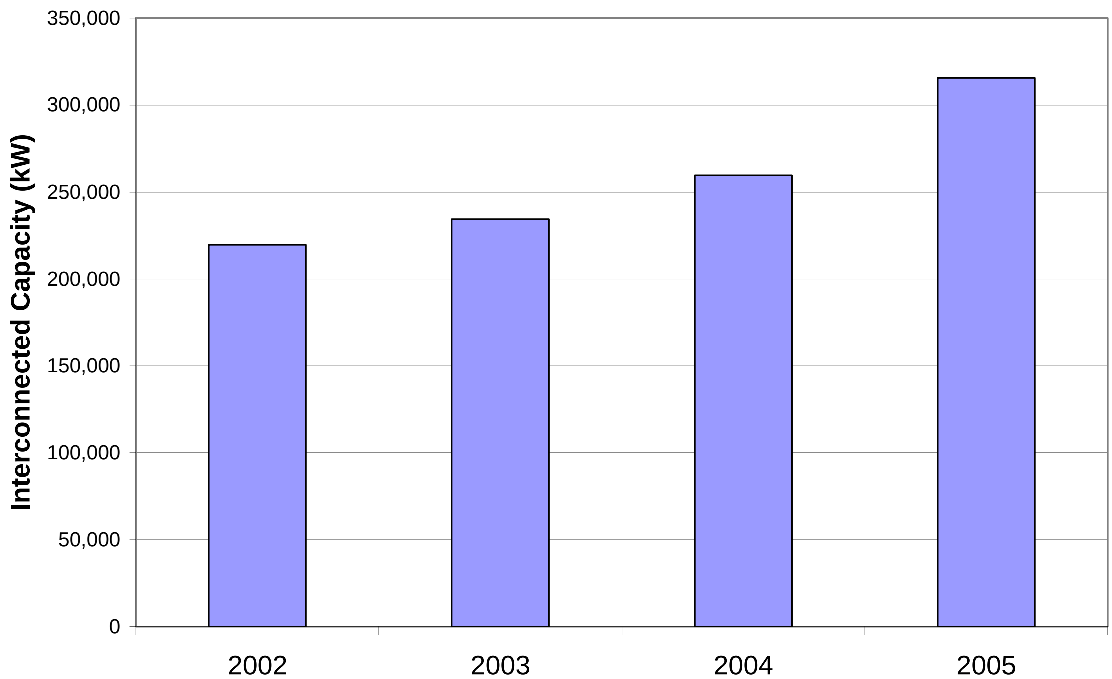
Current DG Approach, Incentives and Tariff Treatment

In Texas, any person that owns distributed generation equipment rated at 1 MW or greater must register as a *self-generator* with the PUCT, assuming the power generated is not intended for sale on the wholesale market. If the DG owner intends to sell the power at wholesale they must register as a *power-generation company*.

The PUCT has adopted Substantive Rules §25.211, *Interconnection of On-Site DG*, and §25.212, *Technical Requirements for Interconnection and Parallel Operation of On-site DG*.

In §25.211, each electric utility is required to file with the PUCT a DG Interconnection Report for the preceding year that identifies each DG facility interconnected on the distribution system. Seven utilities reported DG for a total of nearly 316 MW of interconnected capacity. The total DG activity in Texas from 2002 through 2005 is shown in Figure B-4.

Figure B-4
DG Activities in Texas



Source: Public Utility Commission of Texas

In addition, §25.211 outlines the process for performing pre-interconnection studies, equipment pre-certification, and the interconnection application process.

Section 25.212, outlines the technical requirements for interconnection and the parallel operation of on-site DG. This section describes the typical interconnection requirements, however, each case is unique, and if the typical case is inappropriate, the utility and the DG customer may agree to different requirements.

The PUCT published a DG interconnection manual in 2002 to guide the inclusion of DG in to the Texas distribution system. The manual addresses the main issues or problems associated with the interconnection of DG, including a process for prompt dispute resolution. The manual is directed both at utility engineers to assist in the interconnection application approval process and at DG owners considering interconnection.

The PUCT is proactively supporting DG by simplifying the application, certification and interconnection process.

Regulatory and Market Issues

The PUCT has initiated a proceeding to consider amendments to the Public Utilities Regulatory Policy Act (PURPA) that were enacted in 2005 as a part of the Federal

Energy Policy Act. These amendments established new federal ratemaking standards that state regulatory bodies must consider, relating to net metering, time-based pricing, metering, and communications (smart metering), and interconnection standards.

	Australia	Canada	Denmark	European Union	Japan	The Netherlands	New Zealand	United Kingdom	United States		
									California	**New York**	**Texas**
Siting & Permitting	Classified DG into four categories (<2 kW, 2kW – 1MW, 1MW – 5MW, >5MW).	Siting and permitting is handled at the provincial level, and these issues are being addressed on an individual basis.	DG systems under 25 MW do not require a license to operate.	Members are required to review and improve the process to site, permit and license DG (including renewables and CHP).	Adjusted fire regulations and staffing requirements to assist DG permitting.	Developed three generator categories (< 5 MW, 5 – 60 MW, and > 60 MW).	Fees and requirements vary by size of the DG unit. (< 10 kW, 10kW – 1 MW, 1MW – 5MW, > 5 MW).	Systems under 50 MW do not require a license to operate.	CA has established a number of permit streamlining processes to encourage DG: ▪ All permit applications can be submitted at one time. ▪ The State Permit Streamlining Act provides time limits for environmental studies.	NY does not have a separate electric Generator class. However, the PSC requires gas companies to provide a separate rate class for DG users.	In Texas, systems 1 MW and greater that do not sell power on the wholesale market can register as a self generator, simplifying the application and certification process.
System Interfaces	National Energy Rules establish access arrangements for DG to the network.	Net metering is at various stages of development across Canada.	As a Market participant, a DG facility is assigned a balance responsible party, which is responsible for any imbalance.	EU is continuing to address market access and facilitation of DG resources. Many jurisdictions exempt DG, and in particular intermittent resources, from balancing & ancillary charges.	Allows net metering for any solar installation.	Generation plants > 5 MW need to provide ancillary services except for plants with uncontrollable sources of energy, such as wind. Plants under 60 MW do not have as stringent ancillary service requirements as larger plants.	The LDC must have standard terms and conditions on which it will offer to pay for electricity exported to a distribution network.	The Government is reluctant to introduce net metering due to potential complications in paying and refunding the value added tax that is payable on electricity. Pilot programs are under way in some areas.	Net metering is offered by utilities in CA.	Net metering is available in New York.	PUCT has initiated a proceeding to consider net metering, time-based pricing, metering, communications (smart metering), and interconnection standards
Interconnection Standards	Established working group to address barriers to DG, such as interconnection contract negotiations between utilities and customers.	The Distribution Systems Code, *Appendix F* contains interconnection standards for the generator classes described above.	Danish network operators have developed connection specifications based on size of plant, with less stringent requirements for smaller plants.	Promoting standards for interconnection.		Standardized interconnection in place.	No consistent nationwide standard. Connection is LDC specific.	DTI published Technical Guide to the Connection of Generation to the Distribution Network. In addition, Engineering Recommendations G75/1, G59/1 and G83/1 refer to the connection standards by class.	CA has adapted IEEE Interconnection Standard 1547 specifically for the state of CA and called this standard Rule 21. A Rule 21 working group was established and the group continues to address specific details of the standard.	The PSC has approved standardized interconnection requirements for DG units 2 MW or less and publishes a list of pre-certified interconnection equipment to streamline the process.	The PUCT has adopted rules *Interconnection of On-Site DG*, and *Technical Requirements for Interconnection and Parallel Operation of On-site DG*. The PUCT published a DG interconnection manual.

	Australia	Canada	Denmark	European Union	Japan	The Netherlands	New Zealand	United Kingdom	United States		
									California	New York	Texas
LDC Ownership of DG			A large share of DG facilities are owned by LDC's in Denmark.		Eight of ten utilities created subsidiaries to offer DG services.	Utilities are purchasing and maintaining small CHP units at a customer site then selling the power and heat at reduced rates to the customer. Larger CHP units are co-operated.		LDC's can not own generation equipment.	LDC's are not permitted to own generation equipment	LDC's are not permitted to own generation equipment	LDC's are not permitted to own generation equipment
Stranded Costs	Connection costs are required to be fair and equitable, but the methodology differs by jurisdiction. Potential for stranded costs. This issue is, one of many, being addressed by working groups.	The quantification of stranded costs is handled by the individual provinces.	The large number of DG units has lead to the decommissioning of central plants that were operational and regulated.	The general philosophy is that DG should get credit for the full costs and benefits of access to the system. Therefore, the EU is considering locational pricing such that an accurate pricing signal can be provided to DG developers.		Since all network costs are paid for by the LDC, stranded costs may exist.		Stranded costs are addressed in modeling used to calculate Transmission Use of System (TUoS) and Distribution Use of System (DUoS) charges.	The CPUC has approved tariffs designed to collect a surcharge from customer generation departing load (see Rulemaking 03-09-029).	In NY, exit fees are assess to departing load that will be served by DG systems in order to recover stranded costs. Exit fee exemptions are in place for loads that are replaced by clean on-site generation, such as CHP and renewables.	Recovery of stranded costs through competitive transition charges (CTC's) have expired.
System Investments	Addressing pricing issues, such as delaying or avoiding distribution system upgrades. Utilities are required to pay for network support services and avoided transmission charges.	This issue is primarily a provincial issue and is being addressed by several of the provinces.	The country has seen an increase in T&D costs recently due to the increased quantity of wind generation located in low load areas. Initially T&D improvements were avoided, however.	Addressing avoided costs and benefits of DG.		Generation facilities connected at less than 110 kV do not need to pay transmission costs based on the assumption that facilities connected at lower voltages bring efficiency to the system. Only "shallow" connection costs are paid by the DG facility owner.		Employs locational transmission charges based on where the generation is located, determined by the forward looking long run marginal costs of providing incremental capacity at different points on the network.	Rulemaking 04-04-025 was opened to determine a methodology for quantifying avoided costs that are both time and region specific.		

	Australia	Canada	Denmark	European Union	Japan	The Netherlands	New Zealand	United Kingdom	United States		
									California	New York	Texas
Standby Charges	Addressing pricing issues, such as standby charges that incorporate the benefits of DG on the system and the utility cost for maintaining excess capacity when the DG system is not in use.	The standby charge development is being investigated by some of the individual provinces. This is a significant issue for Canada as DG placement increases.	Priority generation is exempt from the usual balancing mechanism applied to all other market participants. Deviations between forecast and actual production is paid for by the TSO. This cost is shared across all system users.		The capacity charge (kW charge) is 110% of normal when power is used and only 30% of normal when not in use. The energy charge is 110% of normal if the use is planned and 125% of normal is unplanned.			Standby charges are assessed based on the distribution system costs through a Generator Distribution Use of System (GDUoS) charge, modeled by region within a utility's territory.	If a DG unit in California is down and the customer is able to immediately reduce its load, standby costs are minimal. Standby rates were recently updated by the three private utilities. Standby charges are divided in to three categories: ▪ Supplemental ▪ Backup ▪ Maintenance	New York agreed on a standard method to compute standby charges containing two demand charges. ▪ Contract demand ▪ Daily as-used demand.	
Incentives for DG	▪ Photovoltaic Rebate Program (PVRP) ▪ Mandatory Renewable Energy Target ▪ Green Power and the Renewable Energy Development Initiative (REDI).	National incentive programs include: ▪ CCTII and Decentralized Energy Production (DEP) ▪ Technology Early Action Measure ▪ On-site Generation at Government Facilities ▪ Federation of Canadian Municipality (FCM) Green Fund	Any environmentally friendly generation of electricity is eligible for subsidy in Denmark.	Renewable energy sources general receive preferential treatment. This is likely to continue in light of GHG targets.	Cogeneration incentives offered include high depreciation or initial tax credit coupled with low interest loans and subsidies up to 15 percent, depending non the use of heat.	Due to the restructuring of markets, new tariffs and reduced incentives reduce the implementation of CHP, although wind development is strong. Tax discounts are used as incentives for renewable resources and CHP. However, the minimum price for CHP output has been abolished.		Ofgem offers a variety of incentives to encourage LDCs to connect DG and to reflect system costs of DG in pricing structures.	Incentives include: ▪ California Solar Initiative – 10 year, \$2.8 billion program to increase solar capacity by 3,000 MW by 2017. ▪ Self Generation Incentive Program. ▪ Renewable Portfolio Standard – 20 percent renewable target by 2010.	NY incentives for DG include: ▪ Distributed Generation and Combined Heat and Power (DG-CHP) ▪ NYSERDA PV Incentive Program ▪ Solar, wind and biomass property tax exception.	Renewable energy system property tax exemption for the residential, commercial and industrial sectors.